RISK-BASED SELECTION OF SUBSEA LEAK DETECTION TECHNOLOGIES

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Risk-based Selection of Subsea Leak Detection Technologies

by

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ABSTRACT

As traditional oil and gas deposits dwindle, non-traditional marginal reserves are being exploited to further economical and industrial needs worldwide. These reserves are often far from civilization, deep in the sea or in regions such as the Arctic. Now, more than ever, risks related to transporting oil and gas products need to be determined in these remote and sensitive ecological areas. Continuous monitoring of subsea pipelines is the best way to detect leaks quickly and prevent/minimize damage. A number of systems and technologies exist for this purpose. The present work describes two analytical approaches to making decisions related to best technology selection. The first is selecting the best available technology through researching desired parameters and conducting objective analysis. The second approach uses a risk-based methodology for identifying the best technology. The key focus of the present work is to develop a method to quantify uncertainties involved with leak detection technologies on subsea arctic pipelines applicable to harsh environments and use the quantified uncertainty in decision making. This thesis presents both approaches in detail and discusses their application to a real-life case study.

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1. Introduction

1.1. Background

As traditional oil and gas deposits dwindle, non-traditional marginal reserves are being exploited to further economical and industrial needs worldwide. These sites are often far from civilization, in regions such as the Arctic and the deep sea. Because of the remote and ecologically sensitive nature of these operational areas, risks need to be quantified as much as assets. Subsea Leak Detection (SLD) is important for protecting the environment and reducing the risks involved in subsea exploration and production. Small, chronic leaks are difficult to detect and can lead to substantial product loss over time.

Leak detection technologies can be broadly divided into two classes: primary or computational-based leak detection technology, and secondary or hardware-based leak detection technology. An alternative term for these two classes are: intrinsic LDSs (these are general in the flow of the product being monitored) and extrinsic (system located outside of the flow) as seen in Figure 1.1.

While primary leak detection technology, Computational Process Monitoring (CPM) using standard mass flow or pressure balance, is effective, its capability in finding small chronic leakage is extremely limited, and secondary Leak Detection Systems (LDSs) have proven necessary. Monitoring subsea pipelines as often as possible is most effective for catching leaks quickly. A number of options exist to monitor pipelines continuously or intermittently. Intermittent checking of a pipeline can be done with remotely operated vehicles (ROVs), automated underwater vehicles (AUVs), divers with attached sensors, or vapor sensors measuring hydrocarbons at fixed intervals.

Continuous monitoring systems are located outside the pipe. These systems monitor areas around the pipeline for potential leaks. Such systems can include fiber optic cables that measure temperature, sound, and strain along their length; passive and active acoustic measuring of continuous or point sensors; capacitance-based sensors measuring the dielectric constant in a fluid medium; and vapor sensors that sense leaking hydrocarbons.

Determining the location and size of such chronic leaks is important. Even with modern technological options, pipeline leak detection is an ongoing research area and the technology is still emerging. Certain characteristics make some LDSs better than others, for example, the ability to find the smallest leaks, to locate leaks immediately after detection, to continuously monitor an entire pipeline, and to operate in extreme arctic and deep subsea conditions. Certain areas of flow lines, such as connections and valves, are more susceptible than others to leaks, and these may require more focused LDSs as well. The detectability of a leak can depend upon the technology and the specific scenario. Therefore, it is important that a vigorous scientific method be developed that can combine information from multiple sources for proper decision making. Such technology evaluation requires complex decision making and objectivity in the analysis. The proposed risk-based method incorporates a comprehensive decision-making framework involving subjective and objective risk analysis to form comprehensive solutions.

The inputs to risk-based evaluation methodology are based on a literature review, vendor data sheets, and fitness for purpose assessments. Further, detailed evaluation criteria and weights are developed and included in the thesis. The evaluation criteria include smallest leak detection capability, ability to pinpoint exact leak location, false alarm rate, response time, information provided to respond to leak effectively, performance during transient operating conditions (start up, shutdown, and steady state), functionality without visibility (periods of ice cover), performance over long pipeline lengths, temperature and pressure constraints, performance (on seabed and/or buried), installability, rate or volume classification, lifespan of LDS, and multi-use capability.

The following leak detection technologies are included in the evaluation:

- Fiber optic cable (FOC)
- Distributed temperature sensor (DTS)
- Distributed strain sensor (DSS)
- Active acoustic sensor
- Passive acoustic sensor
- Capacitance sensors
- Vapor sensors
- ROV-mounted optical cameras
- Mechanical detectors

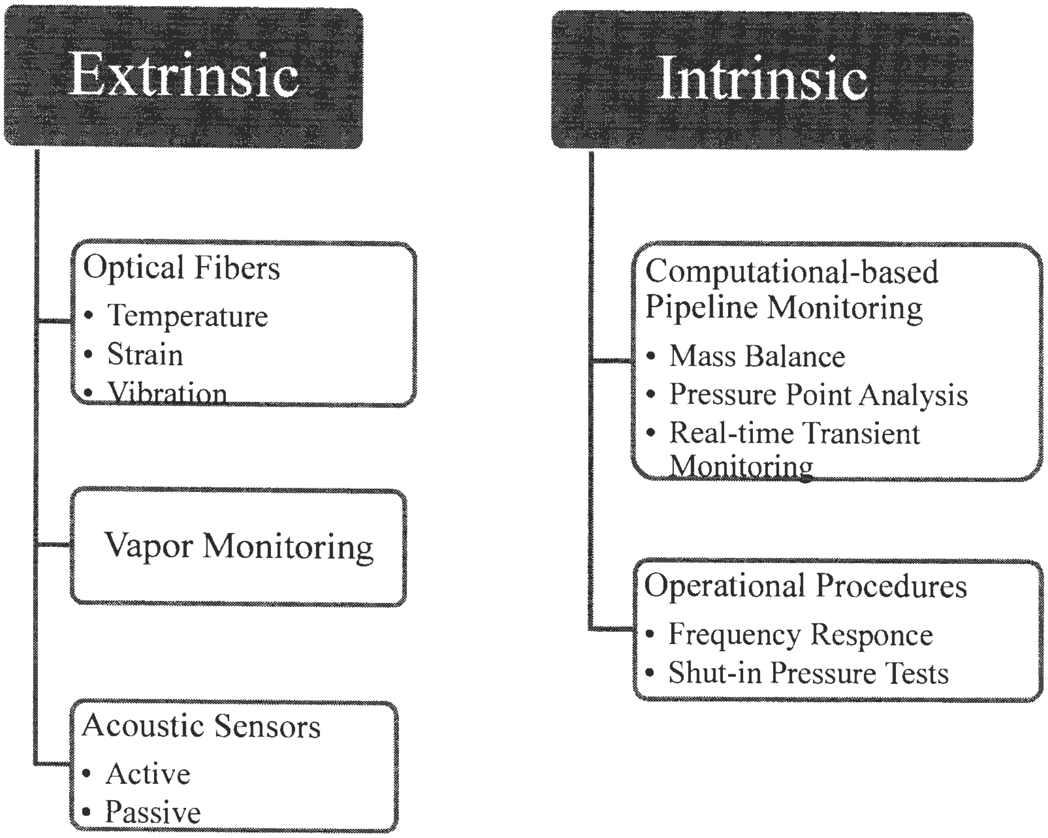


Figure 1.1: Classification of Subsea Pipeline Leak Detection Technologies

2. Literature Review

This chapter provides a comprehensive review of subsea leak detection technologies and technology evaluation methodologies. The working principles of leak detection technologies, specifically the extrinsic leak detection technologies and their advantages and disadvantages, are described in Sections 2.1 to 2.7. In Sections 2.8 and 2.9, various technology evaluation methodologies, namely Technology Readiness Levels, Best Practicable Environment Option, STEP Methodology with Paired Comparison Method, and Multi-Criteria Decision Making, are described, and their strengths and limitations are pointed out. Sections 2.10 and 2.11 discuss risk analysis in engineering.

2.1. Review of Leak Detection Technologies

Figure 1.1: Classification of Subsea Pipeline Leak Detection Technologies shows the classification of LDSs. LDSs are broken into two groups. Intrinsic or primary LDSs use measured flow data such as flow rate, pressure, viscosity, temperature, density, and other factors to detect potential leaks. Usually these instruments are an integral part of the pipeline transport system. The data acquired from these sensors is analyzed to determine the flow conditions and to detect leaks in a pipeline, and can also work in real time to predict leaks. It has the ability to detect large leaks quickly, but has limited ability to detect small, chronic leaks (below 1% of flow). Operational procedures are also involved in the LDSs. Shut-in pressure tests and other tests are used to determine if there is a problem in the source or flow of product along the pipeline.

Extrinsic systems measure changes in physical properties around a pipeline or subsea installation. They can include continuous monitoring using distributed fiber optic cables that detect temperature, strain, and vibration; other intermittent point-sensing methods include cameras, capacitance/dielectric measuring methods, and hydrocarbon vapor sensors. Extrinsic systems are generally used external to the flow, outside the pipeline.

This document evaluates existing LDSs that can be used effectively for rapidly detecting small leaks in subsea pipelines. Since intrinsic methods such as real-time transient monitoring (RTTM), mass balance (MB), pressure balance (PB), and others have limitations in detecting small chronic leaks quickly ([1], [2]), the focus in this evaluation is on extrinsic LDSs that are laid on the seabed or buried in soil. LDSs for both continuous monitoring and intermittent testing are included in the study.

2.2. **Vapor-Sensing Systems (VSSs)**

These systems incorporate a semiconductor to detect hydrocarbon in oil and gas spills, and detect small leaks in the parts per billion. The principle of operation is that hydrocarbon will change the resistance of an intrinsic component in the sensor chamber, which changes electrical signals in the system, alerting an operator. It is a physical form of LDS that does not depend on mass flow or pressure in the pipeline. The various alternative structures of the VSS are described in the following sections.

2.2.1. **Semi-Impermeable Tube**

This method involves a semi-impermeable tube placed along the length of a buried or on-seabed subsea pipeline route. The tube is permeable to air, oil, and gas molecules, but not to water (at shallow depths, as it can withstand hydrostatic pressure) or soil. The tube is vacuumed out and analyzed at regular intervals. If it contains hydrocarbons, an alarm is triggered. This system has been tested and used in (shallow water) subsea and onshore applications ([3], [4]).

2.2.2. **ROV-Mounted**

Systems can be mounted on ROVs or placed as point sensors where oil and gas molecules can permeate membranes and be detected. Figure 2.1 is based on a semi-conductor detector. These types of system do not require a pump or flow around them, because they sample the seawater continuously. Likewise, if a point sensor is placed on an AUV, it will be able to sample along a route travelled [5].

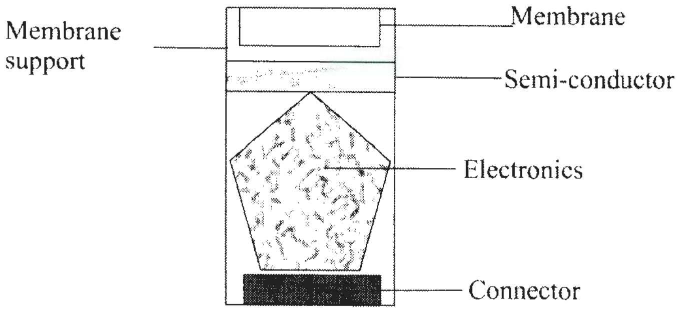


Figure 2.1: ROV-Mounted Sensor (Redrawn from[4])

2.2.3. **Pipe-in-Pipe Design**

A deep-sea pipe-in-pipe design is used to create an annulus between two pipes, which is pumped out daily. The vacuum between the two pipes is beneficial for arctic conditions because of its insulating properties. When a leak occurs in the product flow line, the gas or liquid spills into the outer annulus and is pumped using a vacuum pump to sensors that will detect any presence of hydrocarbon along the line. When hydrocarbon is detected, a signal is sent through the telemetry system, and then action can be taken. A schematic diagram of a pipe-in-pipe vacuum system is presented in Figure 2.2[6]. Using Figure 2.3 the delay between the time the vacuum is started and the time the sensor senses the hydrocarbon can be used to find the approximate location of the leak along the pipeline.

2.2.4. **Capabilities of Technology**

This technology has been installed successfully on arctic subsea systems ([3], [4]) and monitored using semi-impermeable tubes and the vacuum space between pipes. Gas solubility in the deep sea remains a concern if suction lines are used.

2.2.4.1. Advantages of the VSS ([7], [8], [9], [10])

- This system can detect small leaks which cannot be detected by traditional software and/or mass balance/real-time transient analysis methods that are used with intrinsic LDSs. It is sensitive to below 1% of flow rate.
- Pipe-in-pipe systems further insulate the flowing product against the surrounding environment.

- A VSS can locate leaks within 20 m (specifically, 50 m per 10 km in the case of Avera NP semi-impermeable tube)

2.2.4.2. Limitations of VSSs ([7], [8], [9], [10])

- The time required to detect leaks is based on pumping capacity and the time between pumping for pipe-in-pipe and tube systems.
- The detection time is limited by the time between air circulations.
- It is not a continuous operation.
- The sensor must be in direct contact with hydrocarbon molecules for a leak to be detected
- Vacuum annulus monitoring, used with pipe-in-pipe technology, is limited by distance and by the possibility of lifting and installing larger pipelines than normal.
- Deep-sea pressures cause hydrocarbon based gases to dissolve, limiting the high-concentration gas phases around detectors.
- Membrane maintenance and drift of sensor readings are known issues.
- The system depends on ocean currents moving released product to sensors (in the case of ROVs and permeable tubes).
- It is not possible to quantify leak size accurately.
- Semi-impermeable tubes are limited by depth to ~ 6 bar pressure (~30 m)

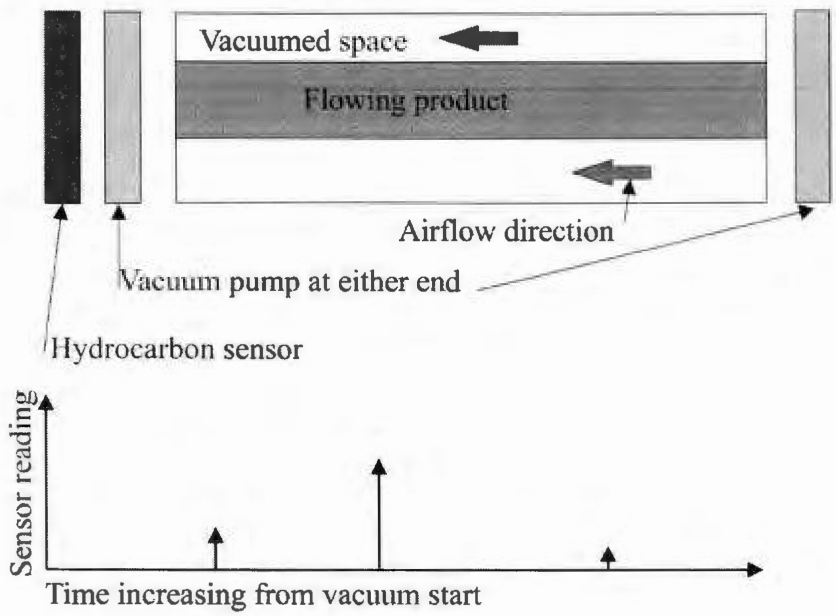


Figure 2.2: Schematic diagram of a pipe-in-pipe vacuum system (Redrawn from[6])

2.3. **Capacitance/Dielectric Sensors**

A capacitance/dielectric sensor is a point sensor that measures the dielectric constant of the fluid that comes in direct contact between capacitive plates. The dielectric permittivity ($\varepsilon_r=C_x/C_0$) is a relation of the value measured using a test capacitor, where C_x is the dielectric constant between two capacitance plates at any time, for a specific material, and C_0 is the capacitance between the two plates in vacuum (a constant value). Because water and petroleum products have different C_x values, it is possible to use instruments to measure when the dielectric permittivity changes for a given scenario. For example, the difference between the dielectric permittivity of water ($\varepsilon_r=\sim80$) and petroleum products ($\varepsilon_r=2.5$) is high. Therefore, when oil comes in contact with the sensor, hydrocarbons are easily detected because of the change in the dielectric constant measured by the sensor.

2.3.1. **Permanently Installed with Shroud**

Permanently installed sensors with shrouds are small, have low power consumption, and are the most widely used subsea leak-detecting sensors of oil and gas. They usually require a collector hood around them to increase the amount of spilled product near the sensor. Direct contact is required for the sensor to detect hydrocarbons. This is an older technology, so it faces fewer unknowns in maintenance and performance. The literature shows [9] that gas is more easily detectable than oil at any depth of water, except depths in which the gas will dissolve. Liquid hydrocarbons in water have been known to coalesce in the collectors, causing some difficulty in detecting leaks [11]. Any natural hydrocarbon releases in the area of the collector hood around the sensor may be detected as false leak alarms. Capacitance sensors need to be placed with collectors above specific small areas (meters squared) and so have very limited use for pipelines. Vapor sensors, described above in Section 2.2.4, are similar in application and leak detectability rate.

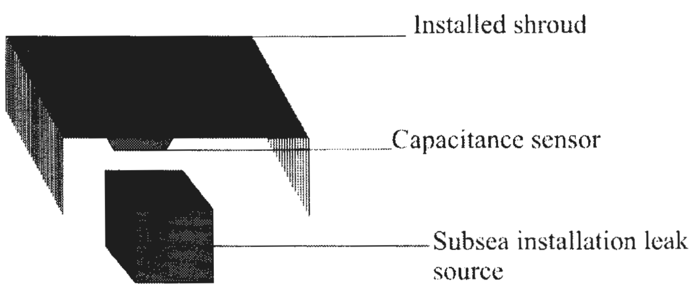


Figure 2.3: Capacitance shroud over installation (redrawn from [12])

2.3.2. Capabilities of Technology

Capacitance sensors have been widely used in the North Sea for subsea monitoring of pipelines and templates. They are placed above points of leaks (pipe joints or production equipment), with steel shrouds that capture leaked material, for better chances of detection. Because of the limited range of collector shrouds, the potential for their use in arctic subsea conditions is poor. Greater pressure differences between product and environment increase detectability as a result of the upward movement of gas, whereas the opposite is true for liquid oil. Because of the ejection velocity of liquid from a pipeline, many tiny droplets spread in water. It was hypothesized that liquid oil droplets floating in seawater require time to collect together, form the liquid phase of oil, and trip the sensor [11]. Further research is required to determine the gas dissolvability and the effects of high subsea pressures on sensor readings.

2.3.2.1. Advantages of Capacitance Sensors ([7], [8], [9], [11])

- Very good detectability of subsea gas releases
- Low power requirements
- Used by industry in the North Sea since the 1990s
- No calibration required

2.3.2.2. Limitations of Capacitance Sensors ([7], [8], [9], [11])

- Physical contact is required between the sensor and petroleum products.
- The only leaks detected are those in the collector shroud.

- Liquid releases are more difficult to sense because liquid does not coalesce as easily as gas in the housing around the sensor.
- Deep-sea pressures cause hydrocarbon-based gases to dissolve, thus causing more difficult collection of trapped oil molecules.
- The amounts of fluid released cannot be known.
- Errors are possible from coalescence product in the sensor collective area.
- The system is not suitable for long pipelines.
- The system is difficult to retrofit on existing structures because additional design is required.
- False alarms can come from natural product releases from seabed.

2.4. **Fiber Optic Cable (FOC)-Based Sensors**

The basic concept of this system is the use of FOC and sensor technology, which can provide distributed temperature, strain, and vibration sensing that, when analyzed, gives information on changes along the length of the pipeline [13]. First, a light is pulsed down a FOC; as it reflects and returns, the reflected signal is analyzed. The FOC is generally strapped to or buried near a pipeline [8]. Disturbances can be caused by vibrations, seismic waves/acoustic signals, or temperature changes from the environment or from contained product in the pipeline being monitored [9]. These FOC methods have the potential to be used as both short point sensors or as distributed cable sensors along pipelines [5].

The FOCs are based on Rayleigh Optical Time Domain Reflectometry (OTDR). It is a well-established method for the characterization of distributions of parameters in optical fibers and is also used heavily in the optical telecommunications industry for quality control (attenuation and linearity) after manufacturing, and after splicing cables for installations. Incident pulses of light (usually 10 ns to 100 ns) are fired down the fibers to be characterized. When the light is propagating down the fibers, some of it is scattered because of inconsistencies in the glass. As the light travels down a length of fiber, some of it is reflected back to the source. This happens continuously, and so the return signal can be analyzed (based on time and distance travelled) and compared to the original emitted light signal. The attenuation in the fiber, the length of the fiber, and any defects or non-linearities can be determined at specific points along the fiber [14]. The FOC-based sensors are broadly classified as distributed temperature sensors (DTSs), distributed strain sensors (DSSs), and distributed vibration (or acoustics) sensors (DVSs or DASs).

The DTS measurement provides information on the distribution of temperature along a sensing optical cable. Some situations involving temperature change include: highly compressed (or liquefied) gas in a pipeline expanding because of the Joule-Thompson effect, high-temperature oil spilling into a cooler environment, and spills warming up the pipeline surroundings near sensors. The DSS provides strain measurement (for detection of pipe strain or ground movement) based on Brillouin scattering of light waves sent in the optical fibers. Temperature increases the anti-Stokes component of the Raman band, while strain does not (Figure 2.4). The DVS provides information on acoustic events, such as those caused by third-party intervention (on onshore pipelines), vortex-induced vibration and anchor impact (for offshore pipelines), or armor wire breakage in flexible risers [15].

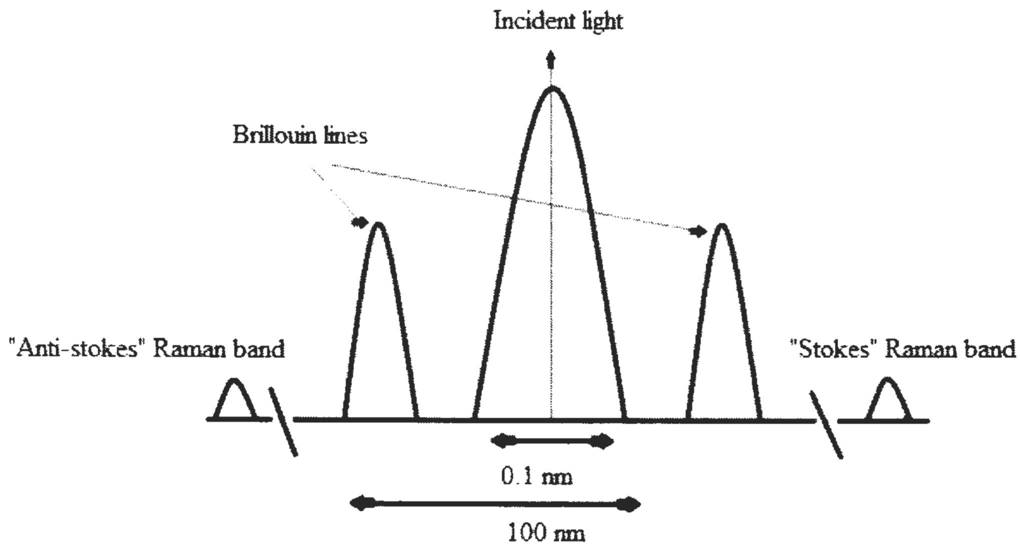


Figure 2.4: FOC Wave Spectrum (Redrawn from [13])

2.4.1. Distributed Temperature Sensing (DTS)

Distributed Temperature Sensing (DTS) uses an external fiber optic cable strapped to a pipeline to monitor temperature along the length of the fiber. The DTS operates on a variant of the standard OTDR described above, where, along with the Rayleigh band reflected from incident light, another, smaller Raman band wavelength is reflected based on individual molecules in the fiber which vibrate due to thermal excitation (reception based on intensity of light received). The Raman-scattered light is due to the thermally-induced molecular vibrations. The Stokes and anti-Stokes portions along the wavelength of light below describe the two relative wavelength sizes for the Raman band temperature sensing. The longer wavelength is attributed to the Stokes line but is only weakly temperature-dependent. The intensity of the backscattered light at the shorter anti-Stokes wavelength increases strongly with temperature; thus, the backscatter of both Raman bands can be used to determine temperature information along an FOC strand. Raman-based systems are limited to approximately 10 km between each new laser/receptor system [12].

For subsea applications, the product leaks must cause changes in the temperature of the surrounding environment in order for a spill to be detected. Erosion conditions can also be predicted by DTS in the case of a buried pipeline in soil. Over time, the product will heat the insulating soil, and a temperature will be distributed along a pipeline. If the seabed is eroded, the area of the buried FOC will also detect the change, and mitigation can be pursued if necessary. It is possible that other environmental changes can offset the temperature as well, but in general, any unjustified and detected change in the temperature of the environment can indicate the release of hydrocarbons.

The temperature change can vary, depending on the product. When liquid single-phase oil pipelines release product, they tend to heat up the surrounding environment, as they are usually heated above ambient temperature to reduce viscosity. Liquefied natural gas (LNG) or gas pipelines tend to cool the environment because of the Joule-Thomson gas expansion effect.

2.4.2. **Distributed Strain Sensing (DSS)**

DSS is based on Brillouin OTDR and relies on the detection of Brillouin scattered waves, which arise from the interaction between the incident photons and thermally-generated lattice vibrations in the optical fiber. The Brillouin OTDR operates in much the same way as Rayleigh OTDR, but measures the spatial distribution of wavelength shifts and/or frequency of the Brillouin scattering, which gives information on strain and temperature conditions in the sensing fiber. This technique uses frequency measurement and is generally more accurate and stable over the long term than Raman, because Raman intensity can suffer from a higher sensitivity to drifts. Brillouin-based sensing techniques are generally faster at detecting environmental changes because of a higher signal-to-noise ratio than Raman, and they can be used over several tens of kilometers until a new extending relay system is required [16].

2.4.3. **Distributed Vibration/Acoustic Sensing**

Distributed Vibration Sensing is similar to the standard Rayleigh OTDR, operating on the same backscatter principle, but using a different principle in sending the light signal and receiving it. The end result is that the system becomes highly sensitive to external influences in the environment (such as anchor drops or vibrations due to leaks). Sound waves (noises) are detectable, which allows for detection of small leaks.

2.4.4. **Capabilities of Technology**

Fiber optic cables and their low propagation-loss characteristics make them good detectors for physical parameter changes along a pipeline over long distances (up to several tens of kilometers). When a leak occurs, researchers have found that after a local temperature change is detected, an increase of 3°K/min was observed [16]. Then the temperature starts to spread laterally at a speed of 0.5 m/min. The study found that it was possible to detect 50 ml/min of oil released and as low as 10 ml/min for chemicals [15], and the precision was within 1 m resolution of the fiber optic cable. The technology can also achieve accuracies below 1°K, provided that the average time between sending and receiving laser signals is correctly set.

2.4.4.1. Advantages of FOC-Based Technology ([5], [9], [12], [16])

- FOC-based systems can detect small leaks which may not be detected by traditional software and mass balance/real time transient analysis methods.
- Simultaneous disturbances may be detected and positioned to approximately one-meter accuracy along the FOC placed along a pipeline.
- No power or electronics are required along the length of the cable and it is immune to electrical interference.
- The quantification of spills is possible as a result of a large change in temperature, sound waves, or other parameters over a length of the pipeline.
- Installation, inspection, and maintenance are straightforward.

2.4.4.2. Limitations of FOC Technology ([5], [9], [12], [16])

- Project experience with this technology offshore is limited.
- Temperature, strain, leak-induced noise, or other physical change must be near enough for the sensor to register it properly and provide a timely alarm.
- This technology is detection-sensitive and time dependent on plume migration for detection. Further study is necessary to understand this.

2.5. **Acoustic Sensors**

Acoustic sensors are classified as passive acoustic sensors or active acoustic sensors.

2.5.1. **Passive Acoustic Sensors**

Passive sensors are underwater microphones or hydrophones; they use sound or pressure waves in water to detect leaks. The passive acoustic detection principle consists of listening hydrophones that detect any surrounding acoustic emissions (Figure 2.5). Valves, machines, and other mechanical equipment and high pressure leaks can be recorded [11]. Because of the excellent acoustic propagation properties of water, this technology is even better suited for subsea monitoring conditions. Using multiple sources to detect changes in subsea acoustics, along with modern signal processing techniques, will provide distance and direction to any acoustic changes in the environment. This will allow the system to detect and locate leaks in a 3D environment. From the intensity of the sound waves, it may also be possible to estimate leak location and size (i.e., small or large).

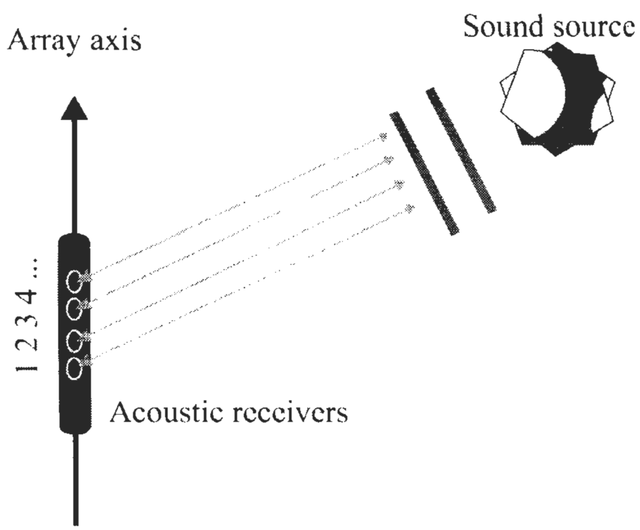


Figure 2.5: Signal separation and noise cancelling (Redrawn from[17])

Usually, subsea leakages from high-pressure sources generate significant noise and this results in their detection. It is also possible to filter out known sounds such as general production noise and natural seepage, so that leaks can be detected and trended despite background noise. If three or more hydrophones are used together, the leakages can be localized by noise triangulation based on the speed of sound in water to determine the distance from each hydrophone.

The sensor array on the Ormen Lange template [17] (which is 1 m in diameter and 1.7 m in height) has high-frequency (HF) and medium/low-frequency sensors (M/LF). The M/LF extends to the 20 kHz range and is primarily used for monitoring structural vibrations and conditions of mechanical systems. Leaks are handled by the HF sensors. The first step of the system (Figure 2.5) is the special sound separation and noise cancellation in the environment. The second step involves analysis of the recorded data; finally, diagnostics of the system are performed. Sound waves in water can also cause shadow waves a short distance behind an object in the water, and then it is only after a certain distance that the waves show up again behind the object. At a 500-meter water depth, Ormen Lange's passive sensors were able to detect gas leaks of 25 standard liters/minute at a change in pressure of 5 bar at a distance of 25 meters. Oil leaks were tested by SINTEF in a basin in Trondheim and detected at 5 L/min, 5 bar pressure change, and a distance of 5 meters. In general, literature has claimed that passive point sensors can cover areas from 100 to 200 feet, and generally this is their spacing along pipelines [10].

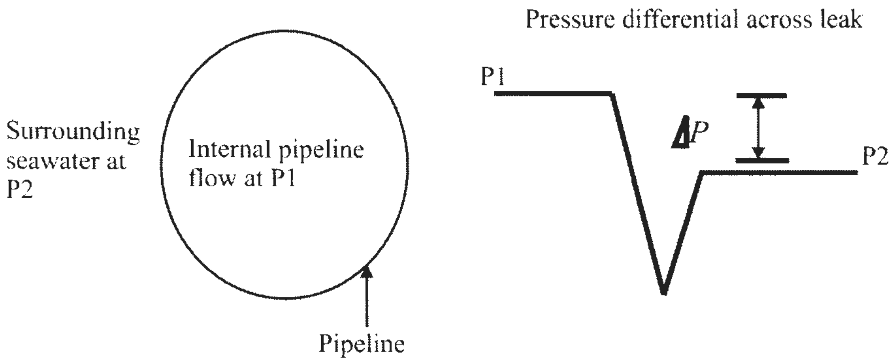


Figure 2.6: Leakage Noise is generated from leak (Redrawn from [17])

Another type of passive sensor measures high-frequency sound waves while being attached to a pipeline. The principle is that the high difference in pressure between the escaping fluids will cause vibrations in the pipe which differ from those sensed in normal operating conditions. Detectability [18] for gas: change in pressure >1 bar with minimum leakage rate 0.1 l/min. Liquid detectability for gas: change in pressure >3 bar, minimum leakage rate 0.1 l/min. The effective distance of this product is unknown (Figure 2.7).

2.5.2. **Capabilities of Technology**

2.5.2.1. Advantages of Passive Acoustic Sensors ([5], [9], [11], [17])

- Less affected by turbidity and sea currents (as opposed to other point sensors).
- Can be used on reverse leaks that may happen in deep water with no external leaks. Can also be used for spatial coverage.
- Positioning is possible using more than two sensors for spatial coverage.
- Acoustic sounds can be detected from nearer than a meter to ~100 m.

2.5.2.2. Limitations of Passive Acoustic Sensors ([5], [9], [11], [17])

- Commercial experience in subsea leak detection is relatively low.
- The sound from a small leak may not reach the hydrophone and therefore may go undetected.
- A sufficient pressure drop over the leak path is a requirement for detection (having sufficient pressure gradient between the pipeline and the surroundings).

2.5.3. **Active Acoustic Sensors**

Active acoustic sensors are employed in inspections for a leak. Usually, the sensor is mounted on an ROV's AUV or towed system and hence it is not a continuous monitoring technique. It works as a point sensor and operates on similar principles of Radio Detection And Ranging (RADAR). Active sensors rely on sending out sound pulses that reflect off the surroundings and return to a hydrophone. The sound travels through a medium and is reflected back with varying intensity related to the objects or media it encounters. The information about reflected waves travelling between different media (boundaries of different impedance) is collected. From this data the leak can be inferred, since the signal changes as the medium changes, because of different densities (and other properties). Other products in this category use 3D acoustic scanning to map entire pipelines.

2.5.4. **Capabilities of Technology**

Acoustic sensors are simple, robust, low-cost systems and have high potential for detection of leaks generating noise [5]. These sensors contain hydrophones (underwater microphones) picking up the pressure wave, or sound, generated by a rupture or leak and transmitted through a structure or water [9].

Based on [11], the results of testing showed that higher-pressure waves generated by leaks were easier to detect than those with less pressure differential than their surroundings. Increasing the distance of the leak to the detector source also lowered the chances of detection. It was determined that crude oil leakages were more difficult to detect than gas leakages (because of varying medium densities). A benefit of active acoustic technologies is that the technology has been used for decades in different fields; the technology just has to be adapted to catching subsea leaks.

2.5.4.1. Advantages of Active Acoustic Sensors([5], [9], [11], [17], [18])

- Provides area coverage so leak positioning is possible.
- High sensitivity available for gas leak detection.
- Advantageous for small leaks or where leaking pressure drop is not sufficient to generate noise.
- High-definition sonar can be placed or mounted on ROVs.
- Able to scan environments with acoustic high definition sonar to obtain a 3D image of the pipeline (resolution depends on background noise).

2.5.4.2. Limitations of Active Acoustic Sensor ([5], [9], [11], [17])

- Sensitive to shadowing of acoustic signals created by subsea structures.
- Typically used on ROVs, solutions for permanent monitoring under development.

2.6. **Optical Methods**

Several types of cameras can be used to detect leaks, including cameras that induce ultraviolet-fluorescence excitation with their own light source, regular direct visual cameras, laser smart Pipeline Inspection Gauges (PIGs) [19], and others. This technology is a point/area sensor and acts as a passive recorder. Technologies that induce fluorescence excitation require an ultraviolet light source, and a camera to record the findings. These systems can include a laser, LED, or light bulb. When the fluorescent material present in the oil is excited during a leak, it emits a different wavelength of light from the original. When the different light is emitted, it is visible on a camera and the operators are alerted on the leak [20]. These are usually used as point sensors, or mounted on ROVs, AUVs, or towed systems to patrol pipelines for leaks.

Though liquid hydrocarbons, and specifically crude oil, have a natural level of fluorescence, dyes are usually added to aid in visually identifying subsea leaks.

2.6.1. **Capabilities of Technology**

2.6.1.1. Advantages of Optical Methods ([9], [4], [11], [20])

- Can detect small leaks which may not be identified by traditional software and mass balance/real time transient analysis methods.
- Simultaneous disturbances may be detected and positioned to approximately one-meter accuracy along the fiber placed along a pipeline.
- No power or electronics are required along the length of the cable and it is immune to electrical interference.

2.6.1.2. Limitations of Optical Methods ([9], [4], [11], [20])

- Being a point sensor, it is not good for continuous monitoring.
- In arctic applications, ice cover may limit visibility.
- Limited distance due to sediment and substances in water may let some leaks go undetected.
- Marine growth on cameras requires cleaning.
- Detectability is limited without introducing dyes into system.

2.7. **Mechanical Devices and Capabilities of Technology**

Recently, a number of mechanical devices have been deployed for subsea leak detection. One example is a gas collection tray over a hydrocarbon subsea installation. When gas rises because of a density differential in seawater, the force raises a metal cover. When the cover is raised, an alarm is triggered.

2.7.1.1. Advantages of Mechanical Technology [5]

- This system can detect small leaks which may not be detected by traditional software and/or mass balance/real time transient analysis methods
- Acts on the simple principle of buoyancy (hydrocarbons are less dense then seawater) where the hydrocarbons get trapped while migrating to the surface

2.7.1.2. Limitations of Mechanical Technology:

- Relatively new concept for extrinsic subsea pipeline use
- Not continuous, coverage is limited

2.8. Review of Technology Evaluation Methodologies

2.8.1. Technology Readiness Levels (TRLs)

TRLs are a systematic measurement system that supports assessing the maturities of technologies. This approach has been used by the North American Space Agency (NASA) for many years and has been incorporated into NASA Management Instruction (NMI 7100). It is also used by the Department of Defense in the United States of America. It has nine levels.

TRL 1: Basic principles are observed and reported. This is the lowest level of the scale, with the least technological maturity. At this level, scientific research starts being translated into applied research and development. An example can include studying silicon (Si) as a monolayer on a substance. The cost to achieve this level is very low.

TRL 2: The technology concept and/or application have been formulated. At this level, after basic physical principles are observed, the next level of maturation and practical research begins. Following the previous example above on Si monolayers, this level would further the research to possible uses of such monolayers. Research may conclude that such monolayers could be used for sensors or other uses. The cost to achieve this is still very low.

TRL 3: Analysis begins of critical function and/or characteristic proof-of-concept. At this step in the maturation process, active research and development are initiated. This step includes analytical and laboratory-based studies. These validate "proof-of-concepts" from TRL 2. An example that follows the previous one would be to plate Si on a metal to ensure it can be used as a sensor.

TRL 4: Components are validated in laboratory environment. Following the success of TRL 3, this level may establish how the pieces will work together to achieve concept-enabling performance levels. Continuing from TRL 3, an example may be testing the properties of Si films on gold substrates to foreign molecules in the laboratory.

TRL 5: A component and/or breadboard validation is conducted in a relevant environment. This is a more advanced and in-depth analysis than the previous level, but still a low-level achievement.

TRL 6: The system model/prototype is tested in a relevant environment to demonstrate readiness. Examples include testing in a simulated operational environment.

TRL 7: The system prototype is demonstrated in an operational environment. This achievement occurs when a complete prototype is demonstrated in an actual operational environment. Examples include an aircraft or vehicle in an operational environment.

TRL 8: The actual system is completed and qualified through test and demonstration. The technology has been proven at this stage in its final form. In general, this level of TRL is the end of system development. Examples include developmental tests and evaluation of vehicles or aircraft.

TRL 9: The actual system is operated under successful mission operations.

Pros: A simple 1-9 level approach to describing technology levels.

Cons: Not useful for risk analysis, unless it is used to judge technologies or criteria, and then AHP or another analysis is carried out.

2.8.2. Best Practicable Environment Option (BPEO)

BPEO consists of 6 basic tasks ([21])

1. Define the objective

2. Generate options for meeting the objective

3 Assess the options

4 Summarize the assessment

5 Identify the BPEO

6. Review the process

This process is similar to other risk assessments for larger projects. The assessment criteria involve environmental impact, environmental risk, health and safety, and others. To evaluate criteria, simple tables are used, some of which include ranges of values from -5 to 5. For example, -5 designates a possible catastrophe, -1 a moderate consequence that may possibly occur. In the evaluation of environmental factors, -5 represents over $10 million in environmental damage while +5 represents $10 million in revenue generated as a result of permanent improvements to the ecosystem. Other criteria are assessed with the same methodology. In the end, the numbers are added together for each scenario that is to be assessed, and the best options will have the highest score.

This method of assessment is relatively simple, and it is related to other risk-assessment methods that involve number scales. The addition of all numbers can give a general idea of the risk to the environment.

The cons of this type of assessment are the limiting analysis, which involves only the environmental assessment, and the use of constricted tables for analysis. The scale of the analysis may also be a problem when there are extreme values, for example, one criteria with a possible $5 million of damage, and another with $5 (is it fair to say one is -5, and other 0 in the overall analysis?). Though the method is quantitative, it relies on the decisions of evaluators for the specific scenario to determine what number to use, and this will add subjectivity. There is also considerable subjective and qualitative analysis involved in generating a conclusion involving a specific number of +/-x.

2.8.3. STEP Methodology with Paired Comparison Method

The STEP methodology was developed as a means for engineers to evaluate technologies [22]. It consists of four steps and generally has the evaluators working with providers of new products to find out which is the best technology. This methodology can also work in other fields and is discussed here in the context of decision making for subsea leak detection technologies.

1. Scoping and Test Strategy: Evaluation teams study the objectives and technology background. The objectives and scope are described, and a survey is made to identify potential technologies. Drafting test methods are also developed.

2. Test Preparation: The products and required infrastructure for testing are acquired. The evaluators and suppliers may meet to discuss the intended use. Specific criteria for testing and the test plan are further developed.

3. Testing, Results, and Final Report: In this phase, the evaluation team tests and scores the technologies for their intended uses. Meetings are held with suppliers to discuss any problems or findings, and a final report is created.

4. Integration and Deployment: Based on the final report, the evaluators consider which product is best to use.

In the STEP evaluation and scoring workflow, each criterion of a technology is scored and assigned a weight for importance.

The STEP method also recommended a paired comparison method for evaluating technologies with 10–100 criteria. This method sorts desired criteria from most to least important. Then, each is assigned a letter. Comparisons involving >, =, and < are used to make equations (i.e., a<b+c and a=b+d, while a is the most important and b, c, and d are less). When the process is completed

and the variables are solved for numbers, the total is summed; if a=10, b=5, c=1, and d=0 then the total would be 16. Each criterion is then divided by the summed value to normalize it, and then each value is used as a weight. A, b, and c could then be .5, .4, and .1 respectively.

The STEP method is widely applicable; however, it uses subjective weights and criteria to judge technologies, and this may influence the final outcome. The paired comparison method is also subjective.

2.8.4. **Multi-step method**

A seven-step method was described by [23]. It is similar to other methods involving criteria and scoring to determine which is the best technology. The steps are briefly detailed below.

1. Establish a team to do a preliminary assessment. This goal identifies all factors for the new technology. The team should implement a pre-evaluation of the technology proposal using quantitative objective factors, or subjective factors if objective are unobtainable, and use estimates in later steps for comparison.

2. Select or reject the proposed technology (to continue evaluation) on the basis of the preliminary assessment.

3. Identify where information is required from technical experts and consultants. The Delphi method (sending questionnaires and surveys to experts and knowledgeable companies for feedback) is recommended.

4. Compare new information arising from step 3 with that used in step 1. The Venn diagram is useful in comparing results recorded in step 1.

5. Assess conflicts comparing information in step 1 and 4.

6. Decide to terminate or proceed, repeating steps 3-5. The Delphi method is again recommended.

7. Conduct a detailed evaluation, considering corporate objectives, strategy, marketing, financial criteria, and production criteria.

The method is comprehensive and easy to follow. The authors included appendices with examples that explain the methodology clearly. However, the method has some cumbersome, repetitive steps. For example, in step 1, pre-evaluation and estimates are made; then, in step 2, selection or rejection of the technology is based on preliminary assessments. In step 4, the authors recommend comparing step 3 with step 1, but it may be better to do all of this in one step. In step 6, the decision to terminate or proceed involves repeating previous steps. Step 7 calls for a further evaluation, which may have been better completed earlier.

2.8.5. **Multi-Criterion Decision-Making (MCDM) Methodology**

Technology evaluations started in the 1950s, when large-scale applications of technology began to affect people's lives [23]. Often, organizations use some form of decision making (technological or otherwise) for different tasks. Most technological evaluations involve information gathering on technologies, and then using some method to compare the desired technology to a requirement. Assessments that can be performed include benefits analyses, risk/uncertainty analyses, simulations, and others.

Multi-criterion decision making (MCDM) deals with choosing the best alternative from a series of possibilities. Decision makers always try to choose the best alternative; however, optimal solutions are only achievable in the case of singular and linear subjects. In most situations, priorities are needed for multi-parameter problems, and this is where the field of MCDM comes in. MCDM models are used to help people make educated decisions. A decision from one set of researchers may be different from another, even the same method is used, since different needs require different prioritizing. The purpose of MCDM is to allow decision makers to feel comfortable and confident about decisions.

MCDM methods have two main components [24, 25]:

1. Preferences in terms of each individual criterion. Specifically, these are models that describe overall performance levels based on individual criteria. The best choice conditions are when individual criteria are used to judge the overall system.

2. An aggregation model (this is more commonly used), in one which allows inter-criteria comparisons that combine preferences across different criteria. Some criteria oppose others, and scoring each criterion may affect the overall results. This model uses a collective effort to achieve the best system performance based on multiple ranked parameters. The system is not chosen based on individual criteria, but with a multitude of alternatives together.

2.9. **Examples of MCDM methods**

2.9.1. **Pareto Optimality**

The basics of the Pareto Optimality (PO) [25, 26] method involve comparing different criteria and finding the best method. If there are two choices, a and b, and if one is better than the other, it is termed dominating. A single point P (Figure 2.7) corresponds to one setting of two criteria. If each P has an equal scoring between two criteria, they are called PO points and are desirable. A PO point by definition is the best possible combination of the two criteria in Figure 2.7. If more Ps are added for different scenarios of the two criteria, then they will be compared; if a P is better in all four quadrants than another P, then the point will be a PO point. If P is better in some quadrant locations and not others, it will be either dominating or inferior.

A simplified general illustration is below for a system with two criteria. There are four quadrant areas around the P point. If we focus on P as the solution to two criteria, the area designated 1 is an inferior point for both criteria. Points 2 and 3 have one criterion maximized but the other less than the P point. Quadrant 4 is the best location, as it is better than the P point. Thus, any P placed in the 4th quadrant would be a PO point. In other words, new situations/criteria are considered and compared to others, and the best combined scenarios, having the most benefits for each criteria, are PO points. Also, each individual criterion will be given the maximum value possible, without subtracting from the other criteria in analysis to reach the maximum possible point in Figure 2.7.

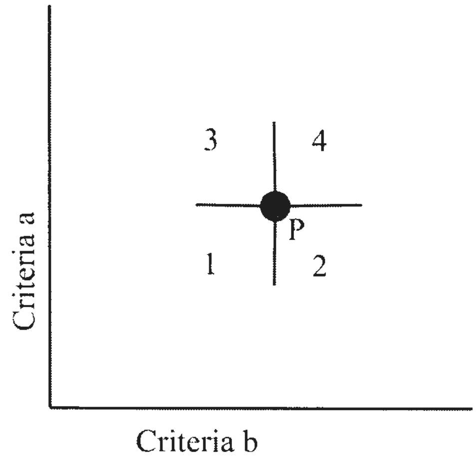


Figure 2.7: PO example with four quadrants and PO point in center.

If the system has more than 2 points, they can be projected onto a two-dimensional plane through further analysis. If a matrix or another means is used, the PO points can be projected and the solutions illustrated graphically as in Figure 2.7.

One major criticism of this approach is that the methodology sometimes requires one criterion to be reduced so that another may increase. For example, in order to test leak detection technologies, with $1000 to spend on a technology, how is it determined what is fair and beneficial to spend on two criteria? Two researchers working on the same problem could assume 800/200 for criteria a/b while another researcher may make the opposite choice. Another disadvantage is that if risk-based analysis is used and monetary value is the deciding factor, then there is no need to use such analysis. It is a cumbersome way to analyze criteria within an industrial setting and can be done effectively only by very knowledgeable engineers.

2.9.2. **Simple Additive Ranking**

This method is an intuitive approach to MCDM based on the ranking of criteria relative to each other, with individual scores using weights for importance [27]. A simple approach would be to assign a score to each criteria, and a weight for each criteria. A weighted average of the scores is used as an overall indicator to select appropriate technology. This gives a simple approach to MCDM, and the scores magnify the differences between criteria.

The benefit of this approach is that it provides a robust, quick, and justified choice for those who have an educated background in the criteria.

The cons of this method are that results can be skewed towards only technologies with the most weighted criteria, since weights are highly subjective. Scores are also subjective if they are used on a ranking scale (for example, 1-10), so decision makers must take care not to have entirely subjective results due to the bias different researchers will have in choosing numbers for the same criteria on the ranked scale.

2.9.3. **Analytical Hierarchy Process (AHP)**

AHP is a general theory of measurement developed by T. L. Saaty. It is used to rank discrete and continuous criteria and make paired comparisons [28]. The comparisons can be based on objective or subjective data. AHP has been used widely in MCDM analysis.

When AHP is used to model a problem, a hierarchic or network structure is created to represent the problem and to establish relations within the criteria. A scale is used to rank each criterion in relation to another, based on importance. This process is based on scoring of 1-9 and is described in Table 2.1.

The relations lead to dominance matrices, which are used to form the ratio scales between selected criteria being evaluated. After the selected criteria are ranked and compared to one another, matrices containing the weights are established. The end result provides a percent value for each alternative technology.

Table 2.1:AHP scale example (redrawn from [28])

Importance on absolute scale	Definition	Explanation
1	Equal importance	Two criteria contribute equally to the decision
3	Moderate imporatance over each other	Experience and judgment strongly favor one activity over another
5	Strong importance	Experience and judgment strongly favor one activity over another
7	Very strong importance	An activity is strongly favored and its dominance demonstrated in practice
9	Extreme importance	The evidence favoring one activity over another is paramount.
Note: 2,4,6,8 are used to balance between 2 judgments.		These are used when compromise in score is needed.

Pros: AHP is comprehensive and used in industry.

Cons: AHP can be a relatively long process when historical objective data is available. Also, when compared to a simple weighted average method with scored criteria and engineering knowledge on the subject, AHP may not be more robust, and it is much more time-consuming for large problems.

2.10. **Introduction to Risk Analysis**

This section deals with understanding risk analysis and issues related to the quantification of uncertainty. The next sections will describe the general methodology of risk assessment while outlining how it is used in the present analysis.

2.10.1. **What is Risk Analysis**

Risk is simply the probability that an event or circumstance will occur, while at the same time, have some negative consequence on humans and the environment. Risk analysis is a systematic process used to identify and assess factors that may jeopardize the success of an event, situation, or scenario. Risk analysis also identifies or quantifies problematic events that are not easily determinable, and it can be used to compare different scenarios to obtain information about the effect of uncertain parameters on an outcome [29]. It generally has a positive effect on decision making and examines the impact that variables (and even their interaction with each other) have on a final outcome. Still, the use of risk-analysis tools remains limited, mostly because application details for specific scenarios are not straightforward [30].

Risk analysis can be applied to almost any field of study where uncertainty exists. It can have substantial affects on personnel and even corporate/government policies. It is used in engineering analysis (reliability analysis and maintenance, drilling analysis, environmental analysis, etc.) [31], finance (investment risks, retirement planning, etc.), operations management (project management, etc.), and environmental sciences (landslides, avalanches, earthquakes, etc.) [32].

2.10.2. **Risk Analysis and Systems Engineering**

Risk analysis is a comprehensive analytical technique that takes into account all aspects of a technology. Systems engineering is distinguished by its practice philosophy, which advocates a holistic approach in thought and decision-making. The engineering is based on modeling methodologies and procedures for the purpose of (1) creating an understanding of the system's nature and its interaction with surroundings, (2) improving the decision-making process, and (3) identifying and quantifying risks and uncertainties within the decision-making process [33]. These properties of systems engineering make risk-based analytical techniques a natural fit for risk-based analysis.

2.10.3. **Risk Calculation**

Risk is based on two things: the probability that an event (usually negative) will occur, based on data, and the consequences when the event occurs. The product of these two events yields the risk present in a scenario.

$$Risk\ =\ Probability\ of Failure\ X\ consequence$$

2.11. Applications of Risk Analysis

Risk analysis is widely accepted and used in the oil and gas industry [31]. It is a powerful tool for certain engineering processes where decisions are required, and it has been used for oil well operations, underbalanced drilling projects [34], and reservoir and completion uncertainties [35]. Other applications also related to oil and gas are hazard analysis of cargo tank explosions on FPSOs (Floating Production, Storage and Offloading), blowout prevention [36], and others.

Risk analysis includes system description, hazard identification, scenario or incident identification, calculation of risk for each category, and consequence analysis. After these steps are complete, an analysis is made of the results, and recommendations can be made [33]. Risk assessments are important in several ways; a primary benefit is that the list of hazards and problem areas for design can be identified from the analysis. Issues that come up from first designs can lead to design changes or result in new approaches. They provide comprehensive information about problem areas and limiting factors in projects. Thus, they are key tools for engineers and project managers.

Some problem identification techniques in risk analysis involve Hazard and Operability Studies (HAZOP) and Failure Mode and Effect Analysis (FMEA). HAZOP involves using Process and Instrument Diagrams (PIDs) or reviewing other systems to determine proper operation procedures and system designs [37]. FMEA was generally limited to single failures in a component or subsystem and can be used with fault trees to determine problem areas. These tools are generally used as a first step in quantitative risk analysis [37]. Another tool is Risk-

Based Integrity Modeling (RBIM), which finds an optimal strategy for inspection and maintenance. RBIM enables the assessment of a component's Probability of Failure (PoF) and the consequences of that failure, and identifies critical components for safe operation.

2.11.1. Risk-Based Technology Evaluation of Liquefied Natural Gas Processes

Risk-based technology evaluation methods have been applied to Gas To Liquids (GTL) and floating Liquefied Natural Gas (LNG) processes and projects [38]. These new technologies have high industrial and economic uncertainties. Thus, a four-step methodology was developed to evaluate uncertainties.

1. Technologies are shortlisted and general associated uncertainties/risks are determined. Two main criteria are used for evaluation in this section: technological availability and degree of development to date. Weighting factors are used to prioritize uncertainties/risks. Questionnaires are also sent to companies to aid analysis; detailed information reviews are completed, and face-to-face meetings are performed to reduce uncertainties. The most developed and least risky technologies are selected for further review in the next steps.

2. More specific uncertainties/risks are identified. Some issues result from known technical risks of the technologies, and others come from a lack of information about the technologies. Again, questionnaires are sent to industry participants to reduce the uncertainties.

3. Uncertainties from stage 2 are further reduced. Further questionnaires are employed to obtain information from studies performed in the past, from research and development cases and from other sources, to reduce risks found in the first steps.

4. Conclusions are drawn from the information obtained.

The ranking method used is described “semi-quantitative,” using a 1-5 scale, from 1 (minimum risk) to 5 (maximum risk), along with a weighting factor for each criteria (for example, in gas pre-treatment for NGL extraction, a weighting factor of 15 is used for acid removal, and for mercury removal, 1 is used). This method was also used when additioning costs. When the degree of knowledge about the technologies is high enough, other areas can be studied, such as failure modes and effect analysis of failures (FMEA).

Pros: This work provides a method to analyze the general uncertainties for new technologies.

Cons: Even though the work is described as "semi-quantitative," it appears to be mostly subjective. Historical, research and development, and other information can be used for quantification of risks. Though this method adds some insight into how to evaluate new technologies, it does not provide an easy way to generalize the methodology. Another problem is that the results of the research may be different for each person evaluating technologies because of the subjective information (weighing factors, questionnaires) involved. Also, it does not provide accurate cost information.

2.11.2. **Completion Design for Subsea Wells**

Risk analysis is applied to determine the best completion design for subsea wells using different technologies. In [39], different scenarios are compared using available technologies for multilateral and intelligent completions. A probabilistic approach using technical, organizational, and environmental issues was considered to assess the uncertainties related to well design, cost, and productivity. A case study was performed with two technologies and two scenario options for a subsea well design. A fault tree approach was used to allow for multiple criteria being considered for failure modes and other issues. After analysis, the costs were converted to a $/barrel (bbl) unit for simplified conclusions.

Different methodologies were considered for qualitative and quantitative analyses. The qualitative steps involved identification of uncertainties and evaluation and categorization of individual risks, with control plans and mitigation. These allowed for a qualitative risk matrix and risk management plan. Quantitative analysis involved cost and duration risk analysis, fault tree models (one for each scenario), and technical unit cost calculations. These allowed for risk models calculated using Monte Carlo simulations.

Risks for each operation and technology were identified and described in terms of triggering events, probability, and impact. Capital expenditure distributions were created for costs associated with each scenario and technology, and sensitivity analysis was performed to determine the top seven factors affecting the risk.

Pros: This is a comprehensive methodology that brings together several standard methods and has the potential to improve output. For example, the fault tree analysis incorporates failure information. Total risks were converted to $/bbl for simple conclusions. Sensitivity analysis was performed to determine the highest contributing criteria for uncertainties. Benefit analysis (cost of technologies along with profit from wells) was also computed to offset the risks in each scenario. In general, a broad scope of risks was considered for the application and fault tree analysis.

Cons: A limited scope of application and technologies was considered.

2.11.3. Risk Analysis on Operations Related to Construction of Oil and Gas Production Systems

Risk analysis related to the construction of oil and gas production systems is described in [40]; it was used to verify engineering operations involving gravity-based structures over drilled subsea wellheads. The economic consequences are great when failures happen because of the remote locations of operation; these consequences can lead to months of lost production time.

The approach to risk analysis was first to determine the causes of failure, and then to develop fault trees based on failure probabilities and consequences. Different failure scenarios for the installation were considered until all scenarios were exhausted. Finite element analysis (FEA) was also performed on the lines connected to the gravity-based structure (GBS), to evaluate effects of boat pull and motion of the GBS on lines. Risk analysis was found to be an excellent tool to document and guide engineering operations that involve economic or technical risks.

2.11.4. Risk Analysis to Upgrade Aging Offshore Lines

A risk-based analysis used for analyzing upgrades to aging offshore trunk lines is described in [41]. Concerns were raised about the risk and consequences of failures associated with older pipelines. Retrofit costs for existing lines were compared to the costs to repair general failures of the aging pipelines.

The authors undertook a risk analysis involving the failures that occur during a pipeline's lifetime; the cumulative risked capital and total risked capital are calculated using a decision tree. Failure rates of pipelines were modeled using probabilities functions, and historical data was used to calibrate the probability functions. The following key parameters were highlighted in the study:

1. Internal corrosion

2. Cost of repairing or replacing leaking pipelines

3. Consequences of leaks

4. Uncertainties in existing corrosion states

5. Cost of retrofitting the existing inspection systems

Pros: This is a comprehensive study that considers uncertainties in pipeline corrosion. It also provides additional information on the costs to upgrade the lines, while incorporating estimated failure data.

Cons: The selection of failure rate density functions is somewhat arbitrary. The methodology for using the decision tree is not clear, and no generalization of the method is shown.

2.12. **Need for Further Research**

The above review shows that risk-based analysis is a comprehensive analytical technique and that it appears best suited for evaluating any new technology, specifically the subsea leak detection technology which is of particular interest. In addition to that, the quantification of criteria to evaluate risk-based scenarios is not straightforward. Therefore, appropriate quantification methods need to be developed.

The main motivations for undertaking this study are discussed in brief below.

- There is a need to develop a straightforward, efficient model that allows for a holistic approach to larger projects and at the same time provides accurate analysis. This model should allow for comparison of criteria, while using the same methodology for all subjects of evaluation.
- Subsea leak detection technology is relatively new; information about different technologies is scarce and it is not clear which are the important factors for the technology. Also, risk-based techniques have not been applied to any similar scenario. Therefore, it is necessary to develop a comprehensive list of evaluation criteria for subsea leak detection technology. Furthermore, the scenario considered in the current application is unique. Therefore, significant research is required to identify the important factors for this particular scenario before a risk-based analysis can be carried out.
- Existing models have limitations. In many cases, the assessment is too subjective or does not include the consequences, and results are difficult to interpret. Thus, there is a need for objective analysis. However, for subsea technology this is difficult, since there is limited history of past operation. In order to bring

objectivity to the analysis, we need to use other indirect indicators. This requires further development in risk calculation using indirect indicators.

- It is important to understand the economic consequences of choosing one technology or application over another when multiple criteria are used. Risk-based methodology can easily integrate cost information from multiple criteria.
- Quantitative risk models are acceptable to industry and easy for engineers to use.

3. Subsea Leak Detection Evaluation Using Performance Criteria

3.1. Executive Summary of Section

This section evaluates the secondary systems and point sensors for different LDSs that are applicable for monitoring of production facilities and subsea pipelines. The evaluation has been based on technological performance criteria. Each technology was assigned a score between 1 and 10, based on their performance for that specific criterion. Final scores were calculated based on a weighted average. Additional weightings are provided for each criteria based on its importance. A weighted average of the scores gave the overall score for each technology. From this technology evaluation exercise, the following can be concluded:

- The applicable technologies to monitor a pipeline for subsea Arctic use are: fiber optic cable (FOC), based distributed temperature system (DTS), distributed strain system (DSS), distributed vibration system (DVS) and distributed acoustic system (DAS), and active and passive acoustic sensors.
- The best technologies for detecting the smallest leak are: FOC DSS, FOC DVS, FOC DAS, and passive acoustic systems.
- The best technologies for locating exact location of leak are observed to be: FOC DTS, FOC DVS, FOC DAS, and passive acoustic systems.
- The best technologies for a buried condition pipeline were: all FOC systems

The fiber optic cable based and acoustic based cables have high potential to be used for subsea applications. However, they need to be tested experimentally to establish minimum thresholds of leak detection and minimum time to detect a leak of that size. Also, more study is required to establish the reliability of such LDSs in subsea conditions. This study recommends further research and development (R&D) in this area.

3.2. **Scenario for Case and Calculations**

In Table 3.1, the specification of the hypothetical pipeline that was the scenario in this analysis is stated. These specifications are based on standard industry practice in the arctic region of offshore subsea pipelines. The pipeline is not buried.

Table 3.1: Pipeline Parameters

Analogue Pipeline Parameters		
OD	610	mm
WT	19.05	mm

Operational Pipeline Parameters		
Q	8000	m^3/hr
V	8.7	m/s
P	68.9	bar
T	60	°C
$T_{seawater}$	-1.7	°C
Oil Density	921.9	kg/m^3
Viscosity	103.9	CP
Specific Heat Capacity	2.2	kg/kg C

Boundary Conditions		
Water Depth	100	m
Current	0.71	m/s

Environmental Condition		
Seawater Density	1025	kg/m^3
Wave H	15	m
Wave T	16.1	sec

For Analogue Pipeline Parameters:
OD=Outside Diameter of Pipeline (in our case it is approximately NPS 24, 24")
WT= Wall Thickness of Pipeline
Operational Parameters
Q=Flow rate

V=Velocity of flow
P_{gauge}=68.9bar
T=Temperature in Celsius

3.2.1. **Objectives**

The goals of this technology evaluation are:

- Understand effective subsea and arctic LDSs including, their advantages and disadvantages, for the purpose of Arctic subsea pipeline leak detection
- Compare the performance metrics of each LDS with relation to its; detectability in the environment, minimum threshold of leak detection, sensitivity, reliability, and robustness
- Conclude the best suitable LDS for Arctic subsea pipeline leak detection and recommend further R&D

Gathering up to date information on the above aspects will provide information on the current state of the technologies, and point towards the need for future R&D. Such a study would facilitate implementation of such technologies for testing and application. A pipeline LDS should have the capability to:

- Detect small leaks
- Locate leaks accurately
- Reduce Non-leak or false alarm rate
- Provide sufficient information to respond
- Provide continuous monitoring along a route
- Minimize installation, inspection and maintenance requirements.

Potential high-risk leak sources are flanges, valves, and fittings. The subsea pipeline may also leak due to damage resulting from corrosion, erosion, cracking and rupture. Potential pipeline leak scenarios should include all portions of the pipeline during all times of the year, especially those that are more conducive to environmental damage and increased economic impact, such as:

- Very small leaks below the threshold of the LDS at locations such as pipe fittings (weeping leaks)
- Leak scenarios associated with progressive loadings (corrosion, seabed erosion features)

3.2.2. Existing and Emerging LDSs

The basic purpose of an LDS is to detect leaks. After that, other goals are: to determine where the leak is, how big it is, and how much product has been spilled; all in a timely manner with a low false-detection rate. The importance of Arctic subsea leak detection technologies has increased greatly with continued exploration and production of hydrocarbons from these regions. The growth continues due to depleting conventional oil and gas reserves worldwide and the increasing energy needs.

The consequences of pipeline leaks can be; loss of commodity, loss of production due to shutdown, the loss due to environmental damage and exposure to legal action. Public and political intolerance to large leak events has increased the consequential cost and scope of related liabilities. This trend is likely to continue into the foreseeable future, and there is a direct link between the total volume spilled and liability costs [42]. This creates a need for continual advancement of LDSs and constant review of existing and upcoming technologies.

3.3. **Extrinsic/Intrinsic Classification**

Some LDSs use process parameters such as temperature, pressure, flow rate, and others, which are typically measured in a pipeline system. These measurements are generally used with condition and performance monitoring systems to find trends in pipeline operations. By generating historical trends for a pipeline system one can assess how likely leaks will occur based on previous measurements of data.

In general the main method to detect leaks uses Computational Process Monitoring (CPM). This involves algorithmic monitoring tools that enhance the abilities of an operator to recognize when an anomaly occurs along a pipeline [2]. CPMs are usually categorized as intrinsic methods of leak detection and they use a combination of physically measured properties (flow rate, pressure waves etc.) and detection algorithms or system models to determine when and where a leak occurs. Other primary methods include operational procedures such as shut-in pressure tests. These systems are good at detecting large loses of product quickly, but take longer to find smaller leaks (if they detect them at all). Some of these methods are [43]:

- Real time transient model (RTTM)
- Pressure wave modeling
- Mass balance methods
- Pressure balance methods

In this review, intrinsic leak detection methods will not be covered (due to limitations discussed in 3.3.1), as the focus of this review is small chronic leaks that are 1% or less of total flow in subsea and arctic conditions.

Other systems are not based on modeling but instead measure the conditions around the pipeline and medium (acoustic information, temperature/pressure of the soil, or water temperature) and these are the focus of this study. Categories of LDSs are: continuous monitoring, intermittent monitoring, and point/area sensors. Continuous monitoring takes place over the entire course of a pipeline (distributed temperature, vacuum sensing); intermittent monitoring involves either all of the pipeline, or some part of it intermittently (ROVs with sensors); point sensors are used as standalone/area coverage sensors (cameras or acoustic sensors). Systems such as acoustic point sensors can be used over the entire length of a pipeline, in effect turning a point sensor into a continuous method of detection. Some of the above external sensors can also be attached to vehicles such as ROVs for subsea use at different locations along a pipeline.

3.3.1. **Limitations of Using Intrinsic Methods Alone**

Intrinsic leak detection methods are not used alone due to their inability to detect small, chronic leaks. Generally intrinsic methods have problems detecting leakage rates of 1% of the flow or lower. Also, even if a small leak is detected it is hard to determine how long it has been leaking, how much product has spilled, or how large an area the spill covers.

Subsea pipelines in Arctic conditions are generally in remote locations not easily accessible by operational crews, and even during flyovers by aircraft, ice cover can hinder finding oil leaks.

Arctic environments also have very sensitive ecosystems. Spills in these conditions pose significant economic and environmental damage, in addition to the damage to reputation a poor safety record will bring. A leak of less than 1% of flow for the months that sea is ice-covered can be catastrophic. A leak of less than 1% of flow can be hard to detect in a pipeline, and because the surface would be covered, flight and ground crews cannot easily witness the spill until the ice melts in the spring. Tens of thousands of barrels could spill in such a time frame, severely affecting the ecosystem.

Use of extrinsic leak detection methods outside of the pipeline have been shown to be effective in finding small chronic leaks quickly, and almost all new pipelines have at least two systems. Nowadays, pipelines in general are constructed with at least one primary LDS for large spills, and a secondary method (or a number of secondary methods) for monitoring small spills, as mandated by regulatory bodies. Arctic and subsea pipelines especially, have multiple internal and extrinsic LDSs for timely and accurate detection of leaks [3].

3.4. **Comparison of LDS**

Using information from Chapter 2 on extrinsic leak detection technologies, a methodology was developed to score the LDSs.

3.4.1. **Evaluation Criteria**

The discussed technologies in Chapter 2 were each evaluated with respect to the following criteria for evaluation:

Leak detection ability:

- Smallest leak detectable (or sub 1% flow rate detection)
- Leak location capability
- Non-leak (false) alarm rate

Response:

- Response time
- Information provided to user for responding

Adaptability:

- Perform with pipeline conditions (startup, shutdown)
- Functionality without visibility (Arctic ice cover)
- Performance over long distances
- Temperature/pressure constraints
- Performance in subsea/buried pipelines

Implementation:

- Install-ability

Additional Features:

- Rate or volume quantification
- Lifespan of LDS
- Multiuse ability

These variables are determined subjectively by experts, as specific values have not been available in literature.

3.4.2. Critical Evaluation with Assumptions

In order to evaluate extrinsic LDSs it was required to make a review for the technologies used for Arctic subsea leak detection that did not use intrinsic systems. The LDSs have been discussed in Section 3.4 along with the advantages and limitations of each technology.

The technologies reviewed in Section 3.4 have been evaluated with scoring with regard to evaluation criteria based on related industry experience and performance survey, as well as using available white papers and product brochures.

The principal knowledge sources for the technology evaluation are internal INTECSEA knowledge, and the work of S. P. Siebenaler [44]. Scores are assigned to each technology based on their ability to fulfill the goal. The chart format in Table 3.2 will be used for scoring using a scale from 1-10. The highest possible value for scoring is 10 and the lowest value is 1. A score of 10 means that the technology works satisfactorily for its criterion while a score of 1 is very poor ability to fulfill the concerned criterion. In the event that a criteria does not apply to a technology a value of 0 will be assigned.

After scoring on a scale of 1-10, weights were assigned to each criterion to reflect the relative importance of each criterion.

Table 3.2: Scoring Methodology for LDS Evaluation

<table>
<tr><td>Criterion for evaluation (ex. Smallest Leak Detectable)</td><td>Lowest Score (1)</td><td>Mid Score(5)</td><td>Highest Score(10)</td></tr>
<tr><td>Technology A</td><td colspan="3" rowspan="3">This area has subjective scoring from the lowest score (1) to the highest score (10)</td></tr>
<tr><td>Technology B</td></tr>
<tr><td>Etc.</td></tr>
</table>

A detailed description of parameters used for scoring technologies has been presented in Table 3.

Table 3.3: Explanation of Scoring

Evaluation Criteria	Lowest score - 1	Mid score – 5	Highest score – 10
Smallest leak detectable	Cannot detect leak until it is at a level that a CPM system would find.	Can detect leaks below 1% of nominal flow rate (in general cannot be detected by CPM systems)	Can detect *any* leak regardless of size.
Leak location capability	Does not provide leak location abilities.	Can locate a leak within a distance whereby a survey team or ROV could be dispatched to locate the leak site.	Can locate leak within 1-3 meters along a span.
Non-leak alarm or false alarm rate	A large number of false alarms.	Some alarms, but trending or other product-specific capabilities allow for reduction of alarms.	No non-leak alarms produced.
Response time	Driven by discrete intervals for ground or air crews (ex. weekly over flights)	Can detect a leak within one day.	Provides continuous monitoring with the ability to provide leak information within an hour.
Information provided to operators for responding	Only provides an alarm.	Provides information such as location and probable leak rate.	Provides continuous monitoring with ability to detect desired leak within one hour and have an approximate value for how much was spilled.
Detect leaks during transient conditions (startup, shutdown, etc.)	System will not detect a leak during transient pipeline events.	Provides general information such as location and leak rate.	Provides detailed diagnostic tools to allow operator to determine validity of leak without having to go to leak site.

Functionality without visibility (cannot see through environment)	Does not work if leak can't be visibly detected	Uncertainty is increased in poor weather conditions	Does not rely upon direct "line of sight"
Performance over long distances	Discrete sensors make continuous mounting unfeasible.	Allows for continuous monitoring on the order of several km.	Can be installed over a distance of 100km.
Temperature constraints	Cannot operate in particular temperature environment	Uncertainty is increased in extreme temperature.	Works in any temperature condition.
Pressure constraints	Cannot operate in particular pressure environment	Uncertainty is increased in extreme pressure.	Works in any pressure range.
Performance on above ground subsea pipelines	Cannot work on seabed, subsea environment.	Uncertainty increases when used on seabed subsea.	Surrounding water does not effect operation.
Performance on (subsea) buried pipelines	Cannot work in buried condition.	Uncertainty increases when used in buried condition.	Operation is not affected by being buried.
Install-ability	Would require significant work (only assembled when originally constructed).	Could be installed without large infrastructure changes.	Does not require any hardware/power source to be installed along pipeline.
Rate or volume quantification	Can only determine that there was a leak.	The system can make a determination as to whether the leak is "small" or "large"	Can determine amount of leaked product accurately to within several barrels.
Lifespan of LDS	Would only last one year in service.	Would require periodic maintenance in order to have an extended life.	Could be installed and remain on pipeline for up to 30 years or more.
Multiuse of sensor/ Reset ability	Single use after being "tripped" and cannot continue to detect future leaks.	Being "tripped" may affect future sensor readings/may require reset or maintenance.	Doesn't need to be reset and will function well after being "tripped" multiple times.
Note: Lifespan without significant maintenance 0-15 years = 7. 15-30 years and > years = 10.[8]			

In addition to the mentioned scores of evaluation criteria, the following weightings were assigned to each criterion to arrive at distinctive conclusions. The allocated weights are based on the importance of the criteria in detecting and locating leaks accurately.

Table 3.4: Criteria Weighting

Evaluation Criteria	Weight	Description
Smallest Leak detectable (detectability < 1% of flow)	10	High weight, being the most critical criteria
Leak location-identification	10	High weight, being the most critical criteria
Non-leak alarm or false alarm rate	9	Very important, not mandatory, but desirable
Response time	9	Very important, not mandatory, but desirable
Information provided to respond	9	Very important, not mandatory, but desirable
Detect leaks with transient conditions (startup, shutdown, etc)	8	Important, but not necessary as steady state is assumed
Functionality without visibility	9	Very important, not mandatory, but desirable
Performance over long intervals	7	Important, but not necessary as multiple sensors can fix it
Temperature constraints	6	Relevant, not a limiting criteria
Pressure constraints	6	Relevant, not a limiting criteria
Performance on above ground subsea pipelines	8	Important and necessary
Performance on buried subsea pipelines	8	Important and necessary
Install ability	7	Important, but light as far as technology is concerned
Rate or volume classification	8	Very important
Lifespan of LDS	4	Should be reasonable
Multiuse	4	Should be reasonable

The following mathematical relationship applies after a score and weight is given:

$$\textit{Total Weighted Average } \mathbf{w_{av}} = \frac{\sum_{i=1}^{n}[s_i * wi]}{(S_m)} \tag{1}$$

Where S_m= Total sum of maximum scoring of total elements (for our case, 160 from 16 criteria), w_{av}= Weighted average rank for each technology, s_i= Individual score for each technology, w_i = Weight of each criteria.

3.4.3. **Evaluation Scores for LDS**

In this section, scores are assigned to each technology for various performance criteria [10], [11], [17], and [44]. Using Table 3.4, the following tables are made to explain the evaluation method for the technologies in this section.

Table 3.5: Vapor Sensing Tube Scoring

Vapor Sensing Tube				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Various vendors claim that systems detect very small leaks <1% of flow [10]	7	10	70
Leak location	The leak location for gas tubing is around 25m	8	10	80
Non-leak alarm or false alarm rate	Sources other than a direct gas leak (natural releases) may be detected, leading to more false alarms.	4	9	36
Response time	Response time based on when vacuumed could be several hours in between.	6	9	54
Information provided to respond	System provides location of leak.	7	9	63
Perform with pipeline conditions	The system is not reliant upon, or affected by pipeline conditions.	9	8	72
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 15km, the performance decreases at length.	7	7	49
Temperature constraints	Reduced detection sensitivity for low temperatures.	7	6	42
Pressure constraints	Used in 30m water depth (Northstar pipeline in Alaska), but tested for up to 120m.	4	6	24
Perform subsea on seabed	Subsea to 30m, below ground yes. (separate in future iterations)	8	8	64
Performance on buried subsea pipelines	Doesn't work well buried due to travel paths associated with oil and gas.	3	8	24
Install ability	Easily attached	8	7	56
Rate or volume classification	Concentrations only.	5	8	40
Lifespan of LDS	Can last up to 15 years without significant maintenance.	7	4	28
Multiuse	Long use between maintenance.	9	4	36
Overall score		109		828
Note:	Project experience with Alaskan Northstar pipeline			

Table 3.6: Capacitance Sensor Scoring

Capacitance Sensor				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	It was found for a gas leak that for a nozzle with 0.17mm diameter and a ΔP of 5, it was 540 seconds before a 100% reading from the sensor. A 0.7mm nozzle only took 9 secs for the same 100% reading. Liquid crude leaks took longer and were prone to coalescence in the steel shroud collector [11].	6	10	60
Leak location	The leak location for gas tubing is around 25m	2	10	20
Non-leak or false alarm rate	Sources other than a direct gas leak (natural releases) may be detected, leading to more false alarms.	6	9	54
Response time	Response time based on when first alarm occurs after leak.	6	9	54
Information provided to respond	System provides location of leak.	7	9	63
Perform with pipeline conditions	The system is not reliant upon, or affected by pipeline conditions.	10	8	80
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system is usually only placed as a point sensor covering a few square meters.	1	7	7
Temperature constraints	Sensor generally not affected. Working range of sensor -10 to 40 Celsius.	9	6	54
Pressure constraints	Pressure tested to deep-water 400bar (4000 meters).	10	6	60
Perform subsea on seabed	Subsea to 400bar (4000 meters)	10	8	80
Performance on buried subsea pipelines	Does not work well in soil due to requiring oil and gas transportation to sensor.	3	8	24
Install ability	Construction for shroud required over subsea template. As a point sensor it is not suitable for pipelines.	6	7	42
Rate or volume classification	Concentrations only.	6	8	48
Lifespan of LDS	25 years without significant maintenance.	10	4	40
Multiuse	Able to be used continuously.	10	4	40
Overall score		112		816
Notes: Most common subsea sensor for subsea installations.				

Table 3.7: FOC-Based Distributed Temperature Sensing

FOC-Based Distributed Temperature Sensing (DTS)				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Various vendors claim that systems detect very small leaks. A quantitative value is unknown, though temperature of 1-3 degree difference in environment has been recorded [10].	8	10	80
Leak location	The leak location for gas tubing is around 1m per 10 km of pipe depending on FOC material and size.	10	10	100
Non-leak or false alarm rate	Sources other than a pipe leak may set off alarms. Spring runoffs in an arctic zone or a buried pipeline becoming uncovered are examples that may cause temperature fluctuations.	6	9	54
Response time	Response time very quick for large temperature changes (less than 1 min), and 1-3K/min was found for smaller leaks. (typically 20sec to 5mins, with normal within 2min)	10	9	90
Information provided to respond	System provides location of leak and temperature variance.	9	9	81
Perform with pipeline conditions	The system is not reliant upon, or affected by pipeline conditions.	8	8	64
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 30 km, and range extenders increase this to 100km.	9	7	63
Temperature constraints	Temperatures near the product flow temperature will cause this technology to stop reading spills. It is unlikely though the environment will have the same temperature as the flow.	5	6	30
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Subsea to extreme depths.	10	8	80
Performance on buried subsea pipelines	Buried works well to measure surrounding and soil temperature.	10	8	80
Install ability	Easily attached to pipe. Must be attached to whole length.	5	7	35
Rate or volume classification	Time of change in temperature will give approximate leak size and rate. Slow temperature change means relatively small, while fast temperature change means large spill.	6	8	48
Lifespan of LDS	Over 15 years life without significant maintenance.	10	4	40
Multiuse	Sensor is not affected by being "tripped" continuously.	10	4	40
Overall score		136		1035

Table 3.8: FOC-Based Distributed Strain Sensing

FOC-Based Distributed Strain Sensing (DSS)				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Detects changes as low as 6 micro strain along a pipeline [10]	9	10	90
Leak location	Within 10m	7	10	70
Non-leak alarm rate	Low false alarm rate as cable attached permanently to pipe.	8	9	72
Response time	FOC has a 20sec to 5 min response time, the average around 2mins.	10	9	90
Information provided to respond	System provides location of leak and strain/vibration/acoustic information, where one can assume hole size based on turbulence received.	8	9	72
Perform with pipeline conditions	The system is not reliant upon pipeline conditions, but will be affected by nearby mechanical devices, such as pumps and valves.	6	8	48
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 30 km, and range extenders increase this to 100km.	9	7	63
Temperature constraints	Only extreme temperatures may affect the strain in the cables due to temperature expansion, however for any conditions of measurement temperate is a factor.	8	6	48
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Subsea to extreme depths.	10	8	80
Buried Pipeline	Buried works well to measure strains and impact sounds on ocean floor.	10	8	80
Install ability	Easily attached to pipe, two fibers required 90 degrees apart for 2-axis strain detection. Cable must be fully adhered to the pipe.	6	7	42
Rate or volume classification	Time of change in strain will give approximate conditions around pipe but will not allow estimation of leak size.	7	8	56
Lifespan of LDS	Over 15 years life without significant maintenance.	7	4	28
Multiuse	Sensor is not affected by being "tripped" continuously.	10	4	40
Overall score		135		1029

Table 3.9: FOC-Based Distributed Strain Sensing

FOC-Based Distributed Strain Sensing (DSS)				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Detects changes as low as 6 micro strain along a pipeline [10]	9	10	90
Leak location	Within 10m	7	10	70
Non-leak or false alarm rate	Low false alarm rate as cable attached permanently to pipe.	8	9	72
Response time	FOC has a 20 sec to 5 min response time, the average around 2 mins.	10	9	90
Information provided to respond	System provides location of leak and strain/vibration/acoustic information, where one can assume hole size based on turbulence received.	8	9	72
Perform with pipeline conditions	The system is not reliant upon pipeline conditions, but will be affected by nearby mechanical devices, such as pumps and valves.	6	8	48
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 30 km, and range extenders increase this to 100km.	9	7	63
Temperature constraints	Only extreme temperatures may affect the strain in the cables due to temperature expansion, however for any conditions of measurement temperate is a factor.	8	6	48
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Subsea to extreme depths.	10	8	80
Buried Pipeline	Buried works well to measure strains and impact sounds on ocean floor.	10	8	80
Install ability	Easily attached to pipe, two fibers required 90 degrees apart for 2-axis strain detection. Cable must be fully adhered to the pipe.	6	7	42
Rate or volume classification	Time of change in strain will give approximate conditions around pipe but will not allow estimation of leak size.	7	8	56
Lifespan of LDS	Over 15 years life without significant maintenance.	7	4	28
Multiuse	Sensor is not affected by being "tripped" continuously.	10	4	40
Overall score		135		1029

Table 3.10: FOC-Based Distributed Vibration/Acoustic Sensing

FOC-Based Distributed Vibration/Acoustic Sensing (DVS/DAS)				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Sensitive to small leaks of ~34 barrels per day. [10]	9	10	90
Leak location	Within 3 m	9	10	90
Non-leak alarm rate	Sensitivity picks up ice scouring, anchor drops, and other subsea disturbances may increase false alarm rate.	5	9	45
Response time	FOC has a 20 sec to 5 min response time, the average around 2 mins.	10	9	90
Information provided to respond	System provides location of leak and vibration/acoustic information, where one can assume a hole size based on turbulence received.	10	9	90
Perform with pipeline conditions	The system is not reliant upon pipeline condition, but will be affected by nearby mechanical devices, such as pumps and valves.	8	8	64
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 30 km, and range extenders increase this to 100km.	9	7	63
Temperature constraints	Only extreme temperatures may affect the strain in the cables due to temperature expansion and affect some readings.	9	6	54
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Subsea to extreme depths.	10	8	80
Performance on buried subsea pipelines	Buried works well to measure strains and impact sounds on ocean floor.	10	8	80
Install ability	Easily attached to pipe. Cable must be fully adhered to the pipe.	7	7	49
Rate or volume classification	Acoustics will give approximate conditions around pipe but will not allow estimation of leak size.	7	8	56
Lifespan of LDS	Over 15 year's life without significant maintenance.	7	4	28
Multiuse	Not affected by being "tripped" continuously.	10	4	40
Overall score		141		1069

Table 3.11: Acoustic (Active) Sensors

Acoustic (Active) Sensors				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Due to different densities, active sensors are very sensitive to gas, but not as sensitive to oil in the presence of water. It was found that a 0.17mm nozzle with a ΔP of 1 bar at 7m was barely detectable, while at 4.5m it was detectable. For crude oil, a 0.7mm nozzle at 2.5m with a ΔP of 5 bar was barely detectable, while a 0.7mm nozzle at 2.5m with a ΔP of 15 bar was detectable [11]. It may be difficult to detect weeping leaks.	7	10	70
Leak location	The leak location for a source can be placed within ~1m (other conditions apply however, like spacing of sensors, and distance from a sensor)	8	10	80
Non-leak or false alarm rate	Sources other than a direct leaks may be picked up, though due to the high frequency sounds used like radar background sounds will not affect the sensor as much as passive acoustics.	5	9	45
Response time	Response time is almost instant in a continuous monitoring situation.	9	9	81
Information provided to respond	System provides location of pressure difference in fluid in an area.	6	9	54
Perform with pipeline conditions	The system is reliant on pipeline flow (pressure in lines) to accurately find leaks.	5	8	40
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed to 100km or more with distances with spacing's of up to 200m each.	8	7	56
Temperature constraints	Not affected.	10	6	60
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Performance on seabed is very good.	10	8	80
Performance on buried subsea pipelines	Being buried will not work well with sound.	2	8	16
Install ability	Due to power constraints and telecommunication between stations, construction of stations 200m apart would take considerable time over long pipelines.	2	7	14
Rate or volume classification	Sound waves due to pressure variation differences in a leak should cause operators to take note when leaks are large or small	7	8	56
Lifespan of LDS	Requires periodic maintenance for extended life (especially when used to continuously monitor a pipeline.	6	4	24
Multiuse	Able to be used continuously.	10	4	40
Overall score		115		866

Table 3.12: Acoustic (Passive) Sensors

Acoustic (Passive) Sensors				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Ormen Lange leak detection test paper: gases with 25sl/min at dP=5bar, and oil leaks 5 l/min at dP=5bar.For ClampON product data sheet: dP>1 bar for gas, dP>3 bar for liquid with a min leak rate of 0.1l/min. Cannot detect "weeping" leaks. [17] SmartBall can detect ~0.5 gpm of flow through holes ~1mm in size, though further oil and gas testing is required [45].	9	10	90
Leak location	The leak location for a source can be placed within 1m (other conditions apply however, like spacing of sensors, and distance from a sensor)	9	10	90
Non-leak or false alarm rate	Sources other than direct leaks may be picked up, and it is only good at detecting leaks in environments without significant background noise. SmartBall testing in pipelines also found that the outer shell should be softer to avoid excess noise while travelling in the pipeline.	5	9	45
Response time	Response time is almost instant in a continuous monitoring situation.	9	9	81
Information provided to respond	System provides location of leak, records sounds for playback, and can be used in frequency analysis. More intense sounds may imply a larger leak.	8	9	72
Perform with pipeline conditions	The system is reliant on pipeline flow (pressure in lines) to accurately find leaks.	5	8	40
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed to 100km or more with distances with spacing's of up to 200m each.	8	7	56
Temperature constraints	Not affected.	10	6	60
Pressure constraints	Not affected.	10	6	60
Perform subsea on seabed	Performance on seabed is very good.	10	8	80
Performance on buried subsea pipelines	Being buried will not work well with sound. (though SmartBall would be fine)	3	8	24
Install ability	Due to power constraints and telecommunication between stations, construction of stations 200m apart would take considerable time over long pipelines.	2	7	14
Rate or volume classification	Sound waves due to pressure variation differences in a leak should cause operators to take note when leaks are large or small	9	8	72
Lifespan of LDS	Requires periodic maintenance for extended life (especially when used to continuously monitor a pipeline and not used as a point sensor).	6	4	24
Multiuse	Able to be used continuously.	10	4	40
Overall score		123		938

Table 3.13: ROV Mounted Optical Sensing Methods

ROV Mounted Optical Sensing Methods				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	Smaller leaks than CPM can be detected, but the leaks must visible. Vendors claim ~1ppb at 5m. Requires use of fluorescence in fluid [10].	7	10	70
Leak location	If leak visible should be placed within several meters.	9	10	90
Non-leak or false alarm rate	Many events may cause the system to produce non-leak alarms.	6	9	54
Response time	Response time is instant based on observer seeing a control screen.	10	9	90
Information provided to respond	System provides visual indication of leak.	5	9	45
Perform with pipeline conditions	The system is not reliant upon, or affected by pipeline conditions.	10	8	80
Functionality without visibility	Does not function.	1	9	9
Performance over long interval	System not reasonable over long distances.	2	7	14
Temperature constraints	For infrared it can cause significant degrading of performance.	10	6	60
Pressure constraints	Extreme depths may affect camera or equipment.	5	6	30
Perform subsea on seabed	Can be used to monitor pipes on seabed, or if they are buried for seepage from soil.	8	8	64
Performance on buried subsea pipelines	Cannot be used on buried pipelines.	1	8	8
Install ability	Point sensors are relatively easily attached to subsea structures.	9	7	63
Rate or volume classification	Can only detect visually small or large leak.	4	8	32
Lifespan of LDS	Not permanently installed, and not subject to lifespan issues (as they are changed periodically, light bulb ~10 years)	7	4	28
Multiuse	Will work for considerable use without maintenance is required.	7	4	28
Overall score		101		765
Note:	Not a continuous form of monitoring; can only be in one location at a time over a pipeline.			

Table 3.14: Mechanical Device

Mechanical Device				
Evaluation Criteria	Description	Score	Weight	Total Weighted Score
Smallest Leak	These mechanical sensors require the release of a product, usually a gas that will physically raise a container and trip a sensor. Many variables come into play in how a gas would migrate to these hoods covering templates. It is likely that at least a barrel or more of gas would need to be released under a hood before the sensor is tripped.	5	10	50
Leak location	Due to being built over subsea structures, it has limited areal coverage.	3	10	30
Non-leak or false alarm rate	Sources other than a direct gas leak (natural releases) may be detected, leading to more false alarms.	3	9	27
Response time	This is based on how fast a mechanical sensor is tripped. It could be a long or short time.	4	9	36
Information provided to respond	System provides general location of leak.	5	9	45
Perform with pipeline conditions	The system is not reliant upon, or affected by pipeline conditions.	10	8	80
Functionality without visibility	Not affected.	10	9	90
Performance over long interval	The system can be installed over distances in the order of 15 km, the performance decreases at length.	1	7	7
Temperature constraints	Not affected.	10	6	60
Perform subsea on seabed	Subsea, to great depths.	8	6	48
Performance on buried subsea pipelines	Would not be useful below ground.	1	8	8
Install ability	Easily dropped and installed, though construction for support may be required.	5	8	40
Rate or volume classification	Quantity known only to trip sensor.	1	7	7
Lifespan of LDS	May require maintenance after period of time due to components installed.	6	8	48
Multiuse	After being "tripped" may require maintenance to return to previous condition.	5	4	20
Overall score		77		308

3.4.4. **Comparison of LDS Performance**

A summary is presented on the next page (Table 3.15) that compares the information gathered in 3.4.3. The weighted average is calculated and shown for the different technologies compared.

Table 3.15: Comparison of LDS Performance

LDS	Total Score	Weighted Average	Best Evaluation Criteria
VSS	109	5.18	Can locate leak well Can perform subsea Not reliant upon pipeline conditions Long use between maintenance
Capacitance	112	5.1	Not reliant upon pipeline conditions Subsea/Extreme pressure tested Long time between maintenance
FOC-Based Distributed Temperature Sensors	136	6.47	Excellent Leak location Excellent response time Subsea/Extreme pressures Buried condition works excellently Long time between maintenance Excellent response time Long range deployment
FOC-Based Distributed Strain Sensors	135	6.43	Excellent strain detection Excellent response time Subsea/Extreme pressures Buried condition works excellently Excellent response time Long range deployment
FOC-Based Distributed Vibration/Acoustic	141	6.73	Excellent vibration and acoustic detection Excellent response time Excellent information provided for leak site Subsea/Extreme pressures Buried condition works excellently Long range deployment
Acoustic Sensor (Active)	115	5.73	Good response time Subsea/Extreme pressure
Acoustic Sensor (Passive)	123	5.86	Great leak detection threshold Great leak location Not affected by temperature or pressure
ROV Mounted Optical Sensors	101	4.78	Excellent response time Not affected by pipeline condition
Mechanical Devices	77	1.193	Not affected by pipeline condition
	Notes: Weighted Average is the Weighted Score from the above section 6. b) ii) divided by 160, the total possible score. Say its normalized to the total possible score		

3.4.5. **Summary**

From the above analysis on the technologies evaluated the following conclusions are derived:

- It is clear from the above quantitative analysis that the best suited overall technologies for subsea leak detection monitoring are FOC-based distributed sensors (all three above scored well), with the best being the distributed strain, and acoustic capabilities.
- There may be special requirements where a technology scoring high may not be the best choice, for example, in the case that a priority is placed on measuring temperature changes, one would want to use FOC-distributed temperature sensors.
- Passive acoustic sensors scored well, and these point sensors can be distributed along a pipeline for maximum coverage. These also scored the highest out of all technologies for the ability to classify the sizes of leaks.
- It is evident from the above analysis that optical sensors mounted on ROVs and mechanical devices have poor capabilities for the purpose of continuous pipeline monitoring.
- The best technologies to monitor a pipeline for small leaks in Arctic subsea application based on the weighted average criteria are: FOC-based DTS, DSS, DVS/DAS systems and passive acoustic sensors.

- All technologies evaluated work satisfactorily for a pipeline on seabed, though FOC systems, acoustics (both active and passive), and capacitance performed superiorly.

3.4.6. **Limitations of Evaluation and Future Work**

The following limitations should be noted:

- This study is based on available literature and under certain assumptions outlined in Section 3.2. Therefore, there could be elements of subjectivity in the analysis.
- Due to the lack of experimental data for technologies, this analysis may be considered preliminary.
- Each leak detection technology uses several sensors. Quantification of the leak detectability is dependent on the performance of individual sensors; therefore more vendor inputs are required to assess the performance of respective LDS.
- A percent concentration in a fluid being measured by a capacitance sensor or vapor sensor can be quantified, while the same quantification cannot be used with a temperature/strain/vibration measuring FOC as both operate on different principles.
- It is possible to judge each technology based on the overall score and weighted average. This was done above in Section 3.4.3. However, in some cases, comparison of one technology to another is not entirely accurate due to different principles of operation, criteria selected, and so on. For example, intrinsic

methods of detection were not considered, even though most of the same criteria apply to them.

- No distinction was made in scoring for oil as opposed to gas leak detection. A further study could study each specific technology and create scoring evaluation criteria to focus only on gas or oil detection. To balance this limitation, the minimum amounts of detectability of oil or gas have been mentioned in the smallest leak detection, wherever possible.
- Weights were assigned as all parameters are not equally significant. For this, industry and expert analysis was used to assign weights. In all cases, parameter weights are calculated subjectively based on industry requirements.

4. Subsea Leak Detection Technologies: Risk-based Decision Making

4.1. Executive Summary

This section presents an evaluation of the Leak Detection System (LDS) based on risk. Risk is defined as the combination of consequences of an LDS failure and the likelihood of an LDS failure. Both objective and subjective analysis, based on research and industry information, were used to evaluate the technologies.

A comparative study was carried out on seven technologies based on different parameters. For risk calculations, the study took into account factors that affect operations, maintenance, and the environment. Based on the calculations, it has been concluded that fiber optic cable temperature, strain, and vacuum tube LDS have the least risk.

This chapter is organized as follows: Section 4.2 of this paper provides an overview of the methodology; 4.5 deals with the ranking methodology, 4.7 with the objective methodology, and 4.10 with conclusions.

4.2. Risk-Based Decision-Making Methodology

The architecture of the risk-based methodology is shown in Figure 4.1. The methodology is applicable to all subsea leak detection technologies, though the current evaluation is limited to extrinsic methods of leak detection. The first step involves short-listing technologies for evaluation, and then all necessary information is collected, using historical and/or subjective information for the calculation of risk. Subsequently, based on the risk, these technologies are ranked. The details of the methodology are described in subsequent sections.

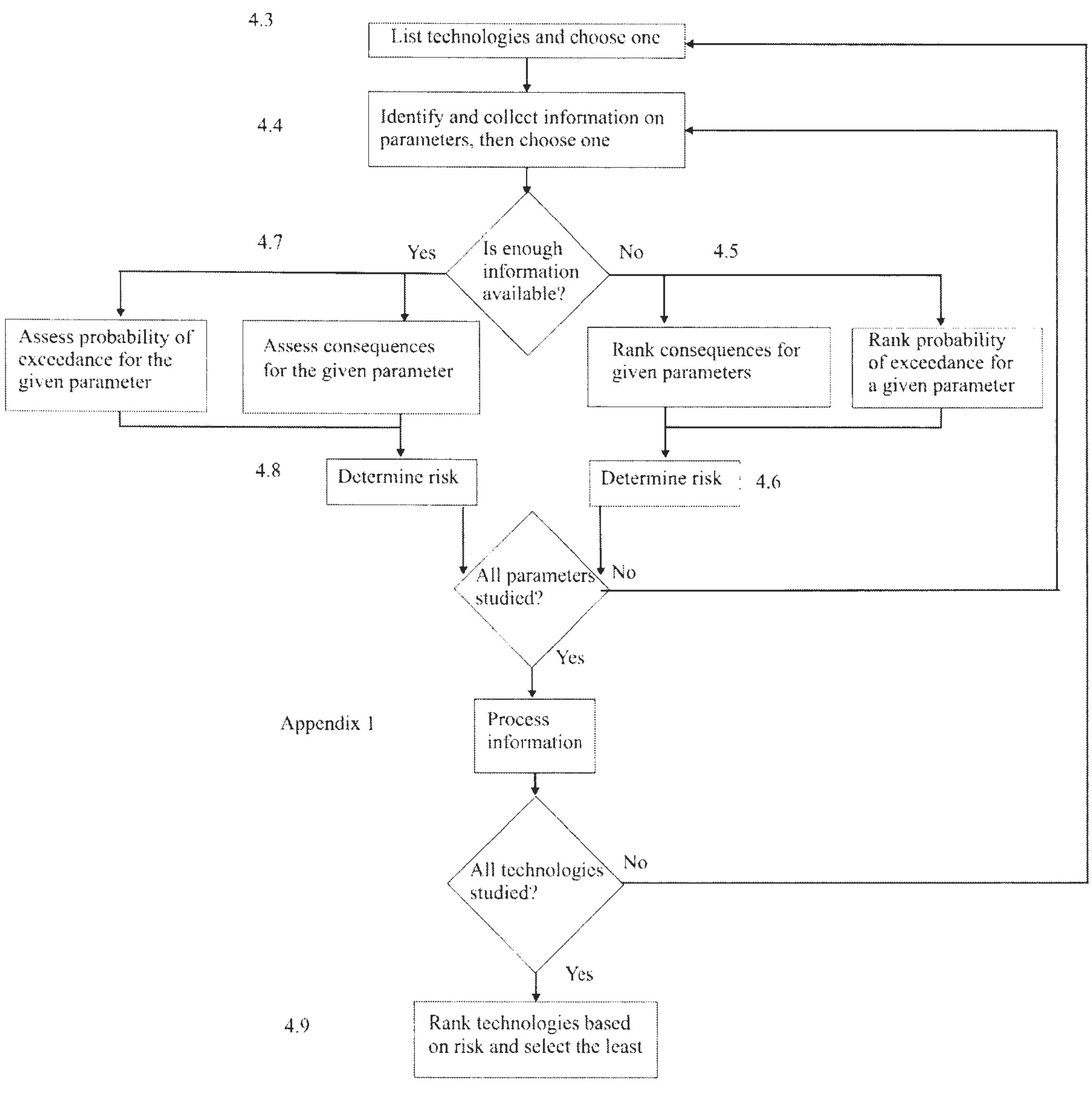


Figure 4.1: Risk-Based Decision-Making Methodology

4.3. **List of Technologies**

The following table lists all technologies that were considered in the comparative study.

Table 4.1: Letters representing technology

Key	
FOC Temperature	A
FOC Strain	B
FOC Acoustic	C
Pipe-in-pipe Vacuum	D
Vacuum Tube	E
Passive Acoustic	F
Active Acoustic	G

These technologies were selected for the comparative study considering detection limits and scenario applicability (i.e., ability to detect small, chronic leaks from subsea pipelines, especially in arctic conditions).

Each of the technologies was evaluated based on all relevant criteria; scores were assigned based on objective and subjective information.

4.4. **Identification of Evaluation Criteria and Information-Gathering**

Each technology was assessed based on three main criteria; further, each criterion was divided into several sub-criteria. A summary of the factors affecting the technology evaluation is given in Figure 4.2, Figure 4.3, and Figure 4.4. The relative weight of each evaluation criterion is given in brackets. These values were subsequently used for overall risk calculation (Section 4.7).

The first category for evaluating leak detection technologies was based on technological factors. Five factors were assessed, each of which was divided into further sub-factors: maturity of technology, subdivided into commercial availability and level of maturity; effect of pipeline flow, subdivided into pressure range, temperature range, flow rate, and solid content; implementation difficulty, subdivided into construction, pipeline distance coverage, and equipment and personnel requirements; and regional considerations, subdivided into local factors of depth, water temperature, water clarity, pipeline buried condition, and tides.

The second category for evaluating leak detection technologies was based on operational factors. Three factors were considered (some with sub-factors): PoF, maintenance (with design life and mean time between failures as sub-factors), and decommissioning.

The third category for evaluation was based on environmental factors. Two factors were considered: Detectable percent of flow, and clean up cost.

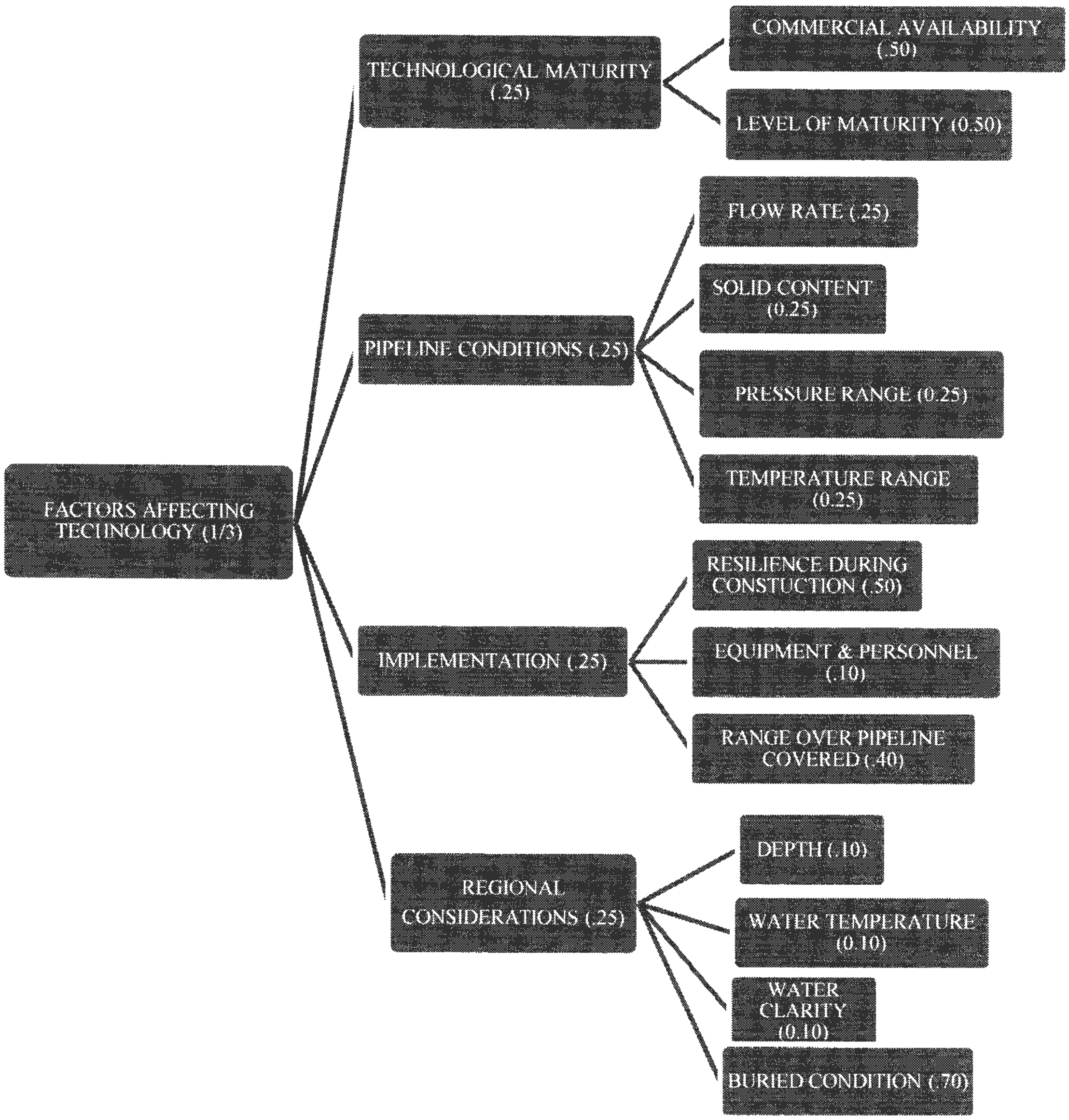


Figure 4.2: Factors affecting technology

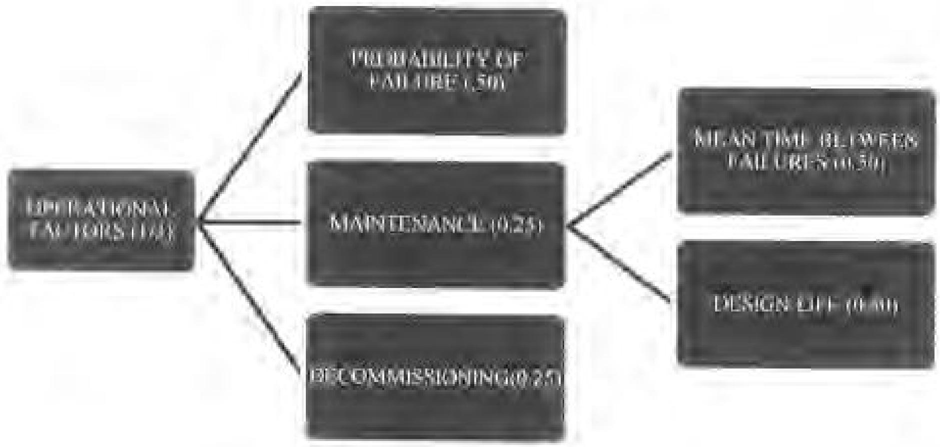


Figure 4.3: Factors affecting operations

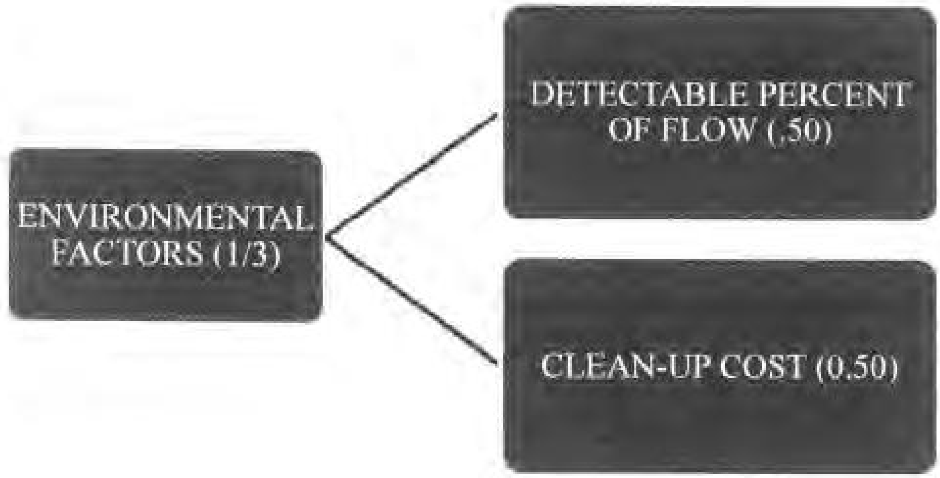


Figure 4.4: Factors affecting the environment

Further details of each criterion are described in subsequent sections.

4.5. **Ranking Methodology**

4.5.1. **Technology Scores**

In this section, the subjective and objective criteria from Figure 4.2, Figure 4.3, and Figure 4.4 are detailed. Each subjective parameter is scored on a relative ranking scale described in Ranking Table 4.2. Each parameter can have a score of 1-9, and this acts as the consequence in the "risk equals consequence multiplied by failure" equation.

Table 4.2: Ranking

Rank	Ranking/Maturity Scale	Affected Detection Level (Flow Conditions/Regional Considerations)	Resilience of Technology (Implementation)	Difficulty (Integration Ability)
9	Basic principles observed and reported	Detection is severely affected	Cannot be installed without damaging technology	Very difficult
8	Technology/concept and/or application formulated	Detection is affected	High level probability of harm	Difficult
7	Analytical and experimental critical function and/or characteristic proof of concept	Detecting is moderately affected	Moderate harm	Somewhat difficult
6	Component and/or breadboard validation in a laboratory environment	Detection level affected is minor	Minor harm	Minor difficulty
5	Component and/or breadboard validation in a relevant environment	Unable to determine if affected	Unknown if harmed during installation	Unknown difficulty
4	System/subsystem model or prototype demonstration in a relevant environment	Probability of detection affected	Probable harm	Possibly difficulty
3	System prototype demonstration in an operation environment	Low probability affected	Low probability of harm	Low probability of difficulty
2	Actual system completed qualified through successful mission operations	Very low probability affected	Very low probability of harm	Very low probability of difficulty
1	System proven through successful mission operations	Not affected at all	Easily installed without harm to technology	No difficulty (relative) present

4.5.2. **Technological and Operational Factors**

In this section we describe the criteria for further understanding of headings in Figures 9 and 10 and discuss the rationale behind the ranks assigned to the technologies for various technological factors.

4.5.2.1. Technological Maturity

In order to assess technological maturity, information was gathered on the commercial availability and the level of maturity of each technology. The best technologies overall were FOC strain, and then FOC temperature and acoustic.

Commercial availability is a good indication of the readiness of the technology. It is reasonable to assume that any technology reaching this stage has undergone significant research and development. Commercial availability was determined based on information from vendors of different technologies. The information collected is processed following the methodology in Section 4.7 and shows that the best technology is passive acoustic.

Technological maturity is assessed based on the year in which the technology was first used for leak detection (even if not for the specific subsea scenario). The longer a technology was on the market, the better, as vendors had more time to fix any limitations and the technology was at a more mature state. The results of the technology maturity assessment are presented in Section 4.7 and show that the best technologies are vacuum/vapor-sensing tubes.

4.5.2.2. Pipeline Conditions

Pipeline conditions refer to the flow conditions and the effectiveness each LDS for various conditions. The four criteria are flow rate, solid content, pressure ranges during operation, and temperature.

For flow rate, a fully developed turbulent flow in a pipe network creates an acoustic signal, even without moving parts or mechanical components [46]. Thus, the flow rate has a direct effect on the acoustic noise level and variation created. Understandably, acoustic-based detection technologies (FOC acoustic cable, passive and active acoustic) are affected. Even though acoustic signal generation from flow within a pipe is not constant, trends have been recorded, and monitoring for leaks can be assumed to be reliable, as the technologies have been used on subsea production platforms and pipelines [8]. It would be fair to assess the probability of affecting the acoustic-based technologies as 4, because there is a probability of detection being affected by flow generating a background noise that may rise above the level of very small leaks. The rest of the technologies are not affected; thus, they have a rank of 1 and are the better technologies for this criterion.

Solid content causes an effect similar to the flow rate. When solid content strikes the walls of a pipeline, more sound is generated than by liquid. It tends to affect the acoustic signals generated from a pipeline [47]. Even with proper trend monitoring, it is possible that leaks could be missed with FOC acoustic technology/passive acoustic technologies. The potential problems related to this parameter would cause minor detection problems, so a level of 6 is assigned in the ranking table. There is a very low probability of active acoustic being affected because it records sound waves that return while travelling through different densities/mediums; therefore, a rank of 2 is chosen. All other technologies are ranked as 1, since they are not affected.

The pipeline pressure affects the discharge rate of leaks into the surrounding water. A number of acoustic technologies detect leaks based on leak rate at a distance, for a given difference in pressure (Figure 2.6). In general, the greater the pressure difference, the better detection with all acoustic technologies. FOC acoustic and passive acoustic technologies rely almost completely on pressure difference to detect leaks [9],[48]. It is estimated that the detection would be moderately affected for FOC acoustic, so a rank of 7 is assigned. For active acoustic, the measurement principle is based on the difference of densities of fluid and gas in water and the resulting reflected sound wave as it passes through those densities. The detection of oil in water relies upon the oil pooling. This is affected by a number of environmental conditions, though generally active acoustic technologies would not be affected by ejection pressure; therefore, a rank of 1 is assigned.

Due to the nature of detection, temperature changes in the flow generally only affect FOC temperature. The range of detectable temperature in FOC can be from -27^{0}C to 100^{0}C [49]. Trend-monitoring techniques are used so that false positives are unlikely (e.g., arctic runoff in shallow areas). It should be noted that as the flow changes (especially in multiphase flow, where downstream gases expand and cool), temperature readings can vary along a strand of pipe. This would lead to the detection being affected in a minor way, resulting in a rank of 3. The rest of the technologies are unaffected by temperature and score well with 1.

4.5.2.3. Implementation

Implementation involves the difficulty of construction, as well as equipment and personnel requirements and the maximum distance the technology can monitor a pipeline. The best technologies were FOC temperature, acoustic, and vacuum tube.

The resilience of the technology during construction includes the probability of damage during installation. All extrinsic technologies are placed outside the pipe flow and so are usually situated in the harsh environment around the pipeline. They are either buried, placed on the sea floor near the pipeline, or placed along the pipeline. In such environments, there is a probability that equipment will be harmed during construction, laying, or burial. Because FOC-based temperature, strain, and acoustic technologies are placed along the outside of the pipeline, care must be taken so that they are attached at specific locations and the sensitive internal fibers are protected from damage. This internal sensitivity can lead to a chance of minor harm; thus, a rank of 6 is assigned.

A pipe-in-pipe vacuum annulus is generally the most resilient technology, as the inner pipe is protected by an outside pipe. Equipment in the annulus is shielded from the outside environment, and thus almost immune to damage, so the pipe-in-pipe vacuum is given a rank of 1.

A vacuum tube is a versatile and strong cable that is placed at a specific distance from the subsea pipeline. It can be bent severely and still function. It may be buried, placed on the sea floor near the pipeline, or placed along the pipeline. As the probability of harming the cable is low during construction, a rank of 3 is chosen. Passive acoustic technology is placed at similar locations to a vacuum tube, so its rank is the same.

Active acoustic technology (Sonardyne ALDS) is placed at a considerable distance on the sea floor to maintain a larger area to cover leaks. Since it is not a buried, or laid with the pipeline, it has less chance of being damaged due to placement. A rank of 2 was chosen to indicate a very low probability of being damaged.

Pipelines and LDSs require specific equipment and personnel for installation, such as lay vessels, barges, and remotely operated vehicles. Some technologies require more specialized (and potentially more costly) equipment and services than others. Regarding equipment and personnel requirements, the only technology that requires considerably more effort and cost is the pipe-in-pipe system, due to the larger diameter outer pipe, and excess weight. This leads to slower laying time, and a much greater cost than laying standard size pipe. Because of this, a rank of 9 is chosen. The other technologies have moderate difficulty with regard to laying pipe and are ranked as 5.

The distance covered over the pipeline is judged according to the required 100 km monitored pipeline length set in the system scenario. If the technology can cover the entire pipeline, it fulfills the requirement. Using Table 21 and 1-9 ranking criteria, which correspond to 90, and 10 km, a technology with coverage of less than 10 km will have a score of 9 and any technology covering more than 90 km will have a score of 1. Raman FOC (DTS) systems use multimode fibers but have limited distance ranges of around 10 km (without extenders), while Brillouin-based sensing technologies (DSS/DTS) have abilities beyond 50 km [50] in single systems. As long as the range extenders could be placed in subsea areas, there would be little difficulty in covering 100 km or even greater distances [49]. The coverage distance of 10-50 km without range extenders, with an average of 30 km, results in a rank of 7.

Technology E (the vacuum tube) can be placed in sections up to ~2x25 km for each system [51], but the performance decreases with length. Multiple systems can be used together over a length of pipe, though issues involving installation and placement of vacuum pumping stations can be a concern. A rank of 5 is assigned for the coverage distance of 50 km.

Passive acoustic devices can be installed to over 100 km with spacing distances of 30-60m for each sensor [48] along the pipeline. A rank of 9 is assigned due to the need for multiple sensors over a 1-km range, and thus for a large number of individual sensors to cover the entire pipeline.

Active acoustic sonar placed above the pipeline has distance coverage of 500 m, with many large pieces of equipment required to be stationed along the pipeline. This is currently very difficult using Sonardyne ALDS, as they must be battery-equipped or powered by another means. Information provided by Sonardyne indicates that this equipment is meant for platform or close-to-shore use. A rank of 9 is assigned, as the distance covered is less than 1 km. Email exchanges with Sonardyne show that the active acoustic LDS is not yet ready for full pipeline use because of the cost and power requirements.

4.5.2.4. Regional Considerations

External environment factors such as depth, temperature, water clarity, and buried condition were considered under this category to determine their effect on LDS. The best overall technologies were FOC-based strain and pipe-in-pipe vacuum annulus.

As all technologies are to be deployed subsea, they should be able to perform at a pipeline's operational depth. Currently, all technologies perform well and are certified for use at 100 m and beyond (Section 3.2) except for vacuum tubing, as it has only been tested to near 100 m. One challenge is that in deep water, when the hydrocarbon gas phase is inhibited (by dissolving directly into the surrounding high-pressure water), vacuum tubing is less able to detect migrating hydrocarbon molecules. It is not clear at what depth this begins, and without testing beyond ~100 m, vacuum tubing will be rated 3, with a low probability of being effective beyond the 100-m depth. The detection mechanisms of all other technologies perform well at depths greater than 100 m.

Temperature changes can affect instrumentation and sensor readings. All technologies perform well in the temperature range of the scenario except for FOC-based temperature technology. As its detection mechanism is based on temperature, it is affected by changing temperatures along a pipeline and fluctuations in the surroundings. Even so, there is little probability of detection being affected by the changes due to the external environment along a 100-km span, and so a rank of 3 is chosen.

Water clarity, organisms, dirt, and other factors can affect certain LDSs. In the current list, only active acoustic may be affected. Because active acoustic technologies send out acoustic signals at high frequency, they are reflected back when they encounter different mediums in water. It may be possible with enough environmental variables (organisms or growth on or around equipment) that the active acoustic would be affected. Because of this possibility, a rank of 5 is selected for this technology. All other technologies are relatively unaffected and are ranked 1.

A buried condition describes a pipeline covered by soil in a trench or otherwise. It is assumed that the detection levels of FOC-based temperature and acoustic, and passive and active acoustic equipment are affected when covered by soil. Temperature in the area of the spill would be more constant, as the soil already acts as an insulator to trap heat around the pipeline from the surrounding ocean. FOC-based sensors may have slower and less drastic response to an under-soil spill than an open water spill on the seabed. The heat released from the flow may reach a peak level, and then spread along the pipeline. Therefore, it is assumed that the detection will be affected, though to an unknown level, 5.

FOC-based acoustic and passive acoustic sensors may also be affected because of the insulating properties of soil. Vibrations, other pressure, and sound waves would be dampened, which could lower the detection probability or slow the initial detection. Passive acoustic would have difficulty with sounds due to the different physical gradients present in soil, but these technologies have worked well on land for buried pipeline [15]. Passive acoustic technologies that listen to sounds produced in the steel pipe because of the leak are not affected (as these are attached to the pipe and listen for changes in vibration frequencies). Passive acoustic technologies are ranked at 4 in terms of the probability of detection being affected. Active acoustic technology would be affected more than passive acoustic, as it needs to send high-frequency waves that must return to the sensor, and if the pipeline is buried this is likely impossible; a rank of 9 applies.

Vacuum tube leak detection would not be seriously affected by being buried, as the oil and gas molecules permeate the soil with time. It is unknown how long this would take, and so unknown harm is assumed, 5.

4.5.2.5. Decommissioning

Decommissioning (Figure 4.3) is the process to remove the LDS at the end of the life of the pipeline or the LDS. It will be rated in a cost of km of pipe laid per day (km/day). In general, hiring barges and crews for this work is standard, so all numbers will be rated at the same standard. Cost is based on a $/km standard for removing pipeline components. The average cost based on industry sources to remove a subsea pipeline is $750,000 per day at 4 km per day. For a 100-km pipeline, that is approximately $18.75 million.

The challenge for some technologies is the required time to decommission an LDS. Decommissioning a much larger pipe diameter, as used in pipe-in-pipe LDS, or many point sensors placed near a strand of pipe, may take longer than for a smaller, lighter pipeline and a light cable vacuum tube. Ranks that considered these factors were assigned to the technologies.

FOC-based temperature, strain, acoustic, vacuum tube, and passive acoustic equipment is placed very near or attached to the pipeline during laying the pipeline, so the removal of this technology should be easy; therefore, a rank of 2 is chosen. A pipe-in-pipe vacuum annulus would be difficult to remove from the seabed using standard equipment, and therefore it is rated 7. Active acoustic sensors pose moderate difficulty, as the only the sensors need to be removed, so a rank of 4 is chosen.

4.6. **Subjective Probability and Consequence Analysis**

When enough objective knowledge was unavailable for straightforward calculations, the ranking method described above was used. Sufficient information was gathered and parameters were ranked according to Table 4.2. When enough objective information was available direct calculations were used for analysis without the ranking method.

In order to have results that correspond with the objective analysis later in this chapter, the same mathematical method was used for both subjective and objective sections. This parallel methodology places the subjective criteria on the same scale as the objective criteria (with the same methodology), and was used to determine the probability of exceeding the median for a given set of values. The median was taken as the base value, and all criteria were compared to it. Basically, exceeding a median for a given set of values indicates that an event is more likely to occur than the median event. If in Table 4.2 a technology scores a 9 but the median score is calculated as 5, the technology rated at 9 is much more likely to exceed the median performance parameter. A technology with a score of 2, though, would be much less likely to exceed the median performance parameter. The likelihood of exceeding the median is calculated using the following equation:

Lognormal Distribution Time Dependent Failure Model

$$f(t) = \frac{1}{\sqrt{2\pi s t}} exp\left[-\frac{1}{2s^2}\left(\ln\frac{t}{t_{med}}\right)^2\right] \quad (2)$$

Where s is the shape parameter affecting the curve, and t_{med} is the median time to failure. The distribution is only valid for positive values of t and is therefore an appropriate choice for failure distribution analysis. Because the lognormal distribution is a monotonically increasing function, it can be manipulated to Equation 3. The probability of exceedance of t (a specific score) over t_{med} (the median score) can be determined using Equation 3, which acts as the PoF in risk calculation. What is measured on the standard normal distribution is the distance that t occurs from t_{med}.

Logarithmic Equation on Normal Distribution

$$F(t) = \varphi\left(\frac{1}{s} ln\frac{t}{t_{med}}\right) \quad (3)$$

Where φ = probability of exceeding the median of a set of values, s = shape factor of the distribution, t = occurrence of an event (or technology rank/score in this case), and t_{med} = median time for specific criteria.

With the above equation, is it possible to determine how likely it is for one technology (for a specific criterion) to exceed the median value for all technologies. In this way it is possible to judge the technologies based on their individual criteria, which are less than, equal to, or exceeding the median threshold. For example, technologies that exceed a "bad" value median are of less worth than technologies below that threshold.

Weighting is used for each category; for example, under the flow conditions (Figure 4.2), four criteria are evaluated, each with an equal importance. Each parameter is multiplied by ¼ to normalize the risk calculations. In the same figure, regional considerations have five sub-categories, with buried pipeline being the most important.

4.6.1. Risk Calculation from Ranking Methodology

Based on the ranking criteria described in Table 4.2 and the rationale described in Section 4.5, all technologies were ranked for the flow conditions and in this section the procedure is described.

Table 4.3: Flow conditions

Flow Conditions: Solid Content (0.25 Weightage)								
Technology	Ranking	T Median	Φ	ϕ[x]	Parameter Importance	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.25	0.05	$3,000,000	$157,868
B	1	5	-0.80	0.21	0.25	0.05	$3,000,000	$157,868
C	6	5	0.09	0.54	0.25	0.13	$3,000,000	$402,238
D	1	5	-0.80	0.21	0.25	0.05	$4,500,000	$236,802
E	1	5	-0.80	0.21	0.25	0.05	$2,250,000	$118,401
F	6	5	0.09	0.54	0.25	0.13	$3,300,000	$442,462
G	2	5	-0.46	0.32	0.25	0.08	$4,370,000	$353,341

The first step is to determine the probability of exceeding the median for a given technology. This involves finding maximum and minimum possible scores from the technologies. In the case of Table 4.3, the maximum and minimum possible values are 9 and 1 respectively, and the median is 5. The next step is to calculate the probability of exceeding the median. Two different distributions are used. These are explained below.

Lognormal Distribution Time Dependent Failure Model

$$f(t) = \frac{1}{\sqrt{2\pi st}} exp\left[-\frac{1}{2s^2}\left(\ln\frac{t}{t_{med}}\right)^2\right] \tag{4}$$

where s above is the shape parameter affecting curve shape, and t_{med}, the location parameter, is the median time to failure. The distribution is only valid for positive values of t and is therefore an appropriate choice for failure distribution analysis. Because the lognormal distribution is a monotonically increasing function, it can be manipulated to the following form:

Logarithmic Equation on Normal Distribution

$$F(t) = \varphi\left(\frac{1}{s} ln\frac{t}{t_{med}}\right) \tag{5}$$

Where φ = probability of exceeding the mean of a set of values, s = shape factor of the distribution, t = occurrence of an event, or time that an event takes place for each individual technology, and t_{med} = median of the technologies measured for the same criteria.

The probability of exceedance of t over t_{med} can be determined using a Logarithmic Equation on Normal Distribution. It gives a distance between t and t_{med} on the standard normal distribution.

For the flow rate criteria for FOC-based temperature LDSs, a t value of 1, a t_{med} value of 5, and a shape parameter value of 2 are used in calculations. The $\varphi, (-0.8047)$, is found on the normal distribution to be F(t)=0.2105.

Weighting is used to combine different categories. For example, in Figure 4.2, the technological section weight represents 1/3 of the total risk hierarchy (with the other 2/3 being operational and spill factors). Therefore, the risk from technological factors is 1/3 of the total risk. Each category includes sub-criteria with which weights have been associated. For the flow conditions, four criteria were evaluated, each of equal importance. Each sub-criterion is then multiplied by 1/4 so that the total four criteria equate to 1.

Using Table 4.3, the value $\varphi(x) = 0.2105 * 25\% = 0.0526$, which is the weighted probability of occurrence. As the cost of the technology is $3,000,000 the risk is (cost multiplied by weighted probability of occurrence): $3,000,000 * 0.0526 = $157,868.

The risks for all ranked criteria are computed following the same procedure. To ensure uniformity, objective calculations follow a similar method that uses objective values to determine the median and probability of exceedance without the subjective 1-9 scale parameter scale.

Please see Appendix 1: Calculations for all computations.

4.7. **Objective Assessment Methodology**

The objective criteria that have available quantitative information for calculations are in this section. There is no need to rank any values prior to calculation of risk. For example, information is gathered about each technology and the specific values researched will create the median for each case. Figure 4.2 and Figure 4.3 are used below, as in Section 4.6.

4.7.1.1. Technological Maturity

Commercial availability is measured by the number of vendors who can supply a given technology. More vendors providing a technology will generally mean more support and more availability of components for a given LDS. In some cases the LDS was divided into component levels to assess the availability. For example, a pipe-in-pipe vacuum LDS is a combination of vapor sensing tubes and hydrocarbon sniffers. Engineering firms are the actual designers of an entire pipeline with proper components to develop the LDS, so the availability of these individual components defines the availability of the technology.

The probability of exceeding the median number of vendors (t_{med}) is a positive attribute, as exceeding this would show a higher number of vendors available than the median. Thus, the technology would have a lower risk (from the viewpoint of vendor availability) than one with fewer vendors. Because exceeding the median is a positive attribute, to properly calculate the risk in Equation 5, we subtract the $\varphi(x)$ value from 1, which is the probability of occurrence. Subsequently multiplying this probability of exceedance by the cost of the technologies gives the risk. The greater the number of vendors available, the smaller is the risk of availability. The assessment methodology is explained below with numerical examples:

Table 4.4: Vendors for Technologies

	FOC Temperature	FOC Strain	FOC Acoustic	Vacuum/Vapor Sensing Tubes	Passive Acoustic	Active Acoustic
Number of Vendors	5	5	3	8	10	2

Technology information in this section is taken from [4].Technology A, FOC DTS, is available from five vendors: Omnisens SA, Sensa Industrial (Schlumberger), Oz Optics, Sensortran, and Smartec. Technology B, FOC DSS, can be considered to be the same as A from a vendor standpoint, because both use the Rayleigh optical time domain incident light as the detection method. Since most components are the same for both LDSs, FOC DSS is also available from five vendors.

Technology C, FOC Acoustic, is available from three vendors: Sabeus Inc., Sensornet, and Optasense (Qinetiq) [52], [53].

Technologies D and E, pipe-in-pipe and vacuum tube sensing, are available from six vendors: Areva LEOS, Phoenix (formerly NESCO), Praxair, Neptune Oceanographics, Capsum, Phaze Technologies, Contros, and Franatech. Note that pipe-in-pipe technology is not supplied as a complete LDS; rather, components are available from vendors and the complete system will be engineered for use in specific circumstances.

Technology F, Passive Acoustic LDS, is available from eight vendors: Physical Acoustic Corporation, Neptune Oceanographics, Naxys, Sicom (now Weatherford), Co. L. Mar, Clampon, Rocket Science Acoustics, and Avetaq.

Technology G, Active Acoustic, is supplied by two vendors: Sonardyne, and Co. L. Mar.

4.7.1.2. Technological Maturity Level Calculation

Computing the technological maturity level requires the first application date of each technology for leak detection (even if not for the specific subsea scenario here). The first application dates of different technologies are given in Table 24.

The first patent using fiber optic cable with an acoustic measurement along a pipeline occurred in 2005 [54]. Vacuum insulated tubing began to be sold in the US in the 1980s.

Table 4.5: Maturity by Age

	FOC Temp	FOC Strain	FOC Acoustic	Vacuum/Vapor Sensing Tubes	Passive Acoustic*	Active Acoustic
Year of First Application	1999 [54, 55]	N/A (Unknown, so median will be used)	2005	~1982	~1994	2005

Vacuum pipe-in-pipe systems have been used in the Arctic, and should work well for detection of single phase leaks [56].

Passive acoustic systems have been used in different forms along pipelines [10]. Certain technologies use vibrations in pipes [9], and others use sounds generated from leaks travelling through the water to detect leaks in pipe.

Active acoustic types have, for the most part, been used on subsea production installations ([4], [57]) and are better for monitoring multiphase and gas phase pipelines [2]. Col. L. Mar was one of the first vendors to provide subsea monitoring using acoustic technologies, in 1998. The most mature technologies are vacuum sensing tubes and passive acoustic.

Using the mathematical methodology described, the probability of occurrence is determined from median exceedance on the normal distribution; the probability of exceedance for maturity signifies where a particular technology stands with regard to median age of all leak detection technologies and the consequence is the cost of the technology.

4.7.1.3. MTBF

Using the Mean Time Between Failures (MTBF) branch of Figure 4.3, the detailed calculations are presented for this operational factor of maintenance. The minimum and maximum times between failures for all technologies are 5 and 30 years [8]. The t median for Equation 5 used for calculation is then $(5+30)/2=17.5$ years.

Choosing Technology A, FOC-based LDS, and knowing that the MTBF is 25 years, while the median is 17.5, and using the shape parameter in Equation 5 as 2, the values are computed and $\varphi(0.1783)$ is found to be $F(t)=0.5708$ based on the normal distribution (afterwards the weighting is multiplied as well). This gives the failure probability/probability of exceedance in the risk equation. Knowing the failure and the consequence (i.e., the cost of the technology for the scenario), the risk can be determined as above.

Because there are three main risk branches, and multiple sub-branched nodes, each individual criterion caries a subjective weight value. For example, there are four criteria in the section on Maintenance in the Factors Affecting Operations, and the risk is computed as: 1/4 (weight) * 0.5708 (PoE) * 3000000 (Consequence) = $428078.30. The 1/4 is due to the fact that there are four individual criteria of equal importance. Further analysis is provided below (4.8).

4.8. **Risk Calculations for Objective Criteria**

This section presents some examples of the performance of objective risk analysis.

4.8.1. **Risk Analysis Examples**

4.8.1.1. Spill Scenario

The last of the main divisions of the technology evaluation (technological and operational factors being the first and second, respectively) is the environmental spill factor. The PoF is based on the probability of a leak occurring, multiplied by the probability of its not being detected. The consequence is the cost to clean up the leaked oil. The oil that is leaked is the base detection threshold for each technology (converted into a percentage of flow).

First, the pipeline is assumed to move 50 000 bbl/day or 7 945 000 L/day. The leak rate in Canada for 2009 was four leaks per 1000 km of pipeline [15]. Using λ as the rate of occurrence, with calculation of the hazard rate being 4 per 1000 km, the probability of occurrence is calculated by the following.

$$R = e^{(-\lambda * \text{number of km of pipe})} \quad (6)$$

Therefore, R=e^(-4/1000 km*100 km)= 0.6703. There is a 67.03% chance of a leak occurring over a period of one year for a 100 km pipeline.

Note: Calculations of % of detectable flow are based on the technology threshold detection rates.

Leak Risk for Each Technology

$$Risk(of\ specific\ technology) = P_{leak} * (1 - P_{detection}) * Technology\ Cost \quad (7)$$

Where $P_{detection}$ is the probability of the mean flow being detected by the technology.

In general, FOC technologies can detect in the range of 50 ml/min of fluid [9].50 ml/min*60 min/hour*24 hours/day = 72 L/day detection rate. For a detection rate of 72 L/day / 7 945 000 L/day = 0.00000906 or 0.000906 % of flow.

Passive acoustic [3] technologies can detect in the range of 5 L/min of fluid, or 7200 L/day rate [52].For a detection rate of 7200 L/day / 7 945 000 L/day = 0.000906 or 0.0906% of flow.

Pipe-in-pipe vacuum technologies [56] can detect in the range of 1 L/min or 1440 L/day rate [53]. For a detection rate of 1440L/day / 7 945 000L/day = 0.000181 or 0.0181% of flow.

A floating type active sonar acoustic[2] has the ability to detect ~100-500 bbl/day depending on the subsea distance and conditions, and the phase of leaked oil. For analysis purposes, the mean is selected. The detection rate would then be 300 bbl/day, for a detection rate of 300L/day / 7 945 000 L/day = 0.0000387 or 0.00387 % of flow. Calculation details are given below; note that total risk values for each hierarchy are then multiplied by 1/3 (as there are 3 total branches).

Table 4.6: Oil spill calculations

Technologies	Detect able % of flow	$\phi[x]$ Probability of not being detected	POD=1-$\phi[x]$	Cost of Technology	Risk
FOC	0.001	0.440	0.560	$3,000,000	$1,319,617
Pipe-in-pipe	0.018	0.911	0.089	$4,500,000	$4,099,235
Vacuum Tube	0.018	0.911	0.089	$2,250,000	$2,049,618
Passive Accoustic	0.091	0.984	0.016	$3,300,000	$3,248,102
Active Acoustic	0.004	0.713	0.287	$4,370,000	$3,115,952

4.8.2. **Cleanup Cost Due to Spill**

The cleanup cost due to a spill was calculated knowing the detection threshold for each technology from Section 4.8.3. Knowing the number of liters that is spilled before the technology is able to detect the leak is the absolute minimum amount spilled that needs to be accounted for.

The threshold per day for FOC is 60s, and so per day 60/86400=0.0007/day. Knowing that 50,000bbl/day is travelling through the pipeline, that 159 L are in 1 barrel, and the pipeline is known to be moving 184 L/s through the line, the costs to cleanup can be determined.

Table 4.7: Cleanup due to spill

Environment: Minimum Cleanup due to Spill (0.50 weight)					
Technologies	Pipeline bbl/sec	Time in seconds to detect	Amount bbls	Cost per barrel	Total Damage
FOC	0.58	300	173.6	$4,200	$120,313
PIP/Vacuum	0.58	7200	4166.7	$4,200	$2,887,500
Passive Acoustic	0.58	300	173.6	$4,200	$120,313
Active Acoustic	0.58	300	173.6	$4,200	$120,313

4.8.3. **Probability of Failure for Technologies**

This section deals with calculating the reliability of the main components of each technology. For simplicity's sake it will include only the chain of components that begins with the process of leak detection and ends with the analysis and control system (this also includes the telemetry system).

Technologies will be compared to each other based on overall time to failure of the system, the worst component in the system chain, the repair times for components, etc. The fault rate of the system is determined by the reliability of each component. Because this system is modeled as a series system, the overall reliability of the system is given by the multiplication of all elements.

In order to determine specific reliability rates, assumptions for components will be necessary. The average failure rate is represented by λ, with units of failure per time. The probability that a component will not fail during the time interval (0,t) is given by the following Poisson distribution in Equation 8.

Failure Formula

$$R(t) = e^{-\lambda * t} \tag{8}$$

where R is the reliability and constant failure rate is λ. As time goes to infinity, the reliability goes to 0. For the risk analysis, this report will focus on the PoF, which is defined as 1-*R(t)*.

The mean time to failure (MTTF) is computed with the assumption that the failure rates are constant, and so $1/\boldsymbol{\lambda}$ is equal to the MTTF.

The PoF of the system is calculated using values from Chemical Safety Process [33], the Offshore Reliability Data (OREDA) handbook [58], and Lee's Loss Prevention in the Process Industries [59]. In many cases, assumptions for components were made and, to simplify analysis, series connections were assumed.

To illustrate an example of a MTTF calculation, a pipe-in-pipe vacuum pump LDS was selected and described below. In order to calculate specific reliability rates, assumptions at the components level will be necessary. The formula for reliability used is the failure formula in Equation 8. The hazard rate is the failure per unit of time for specific components. For a pipe-in-pipe vacuum LDS, the following assumptions will be used for calculations and simplification:

- The telemetry has a fault/hazard rate of 0.2/year or a 0.2 fault rate [33].
- The hydrocarbon sniffer will be modeled as process sensors (control and safety equipment) with 2.81/10^6 hour failure rate, or a 0.02463 fault rate [59].

- The vacuum pump operation is modeled as a standard pump [58] with 20.52/10^6 hour failure rate or a 0.18 fault rate.
- The console light is modeled as an indicator lamp with a 0.044 fault rate [33].

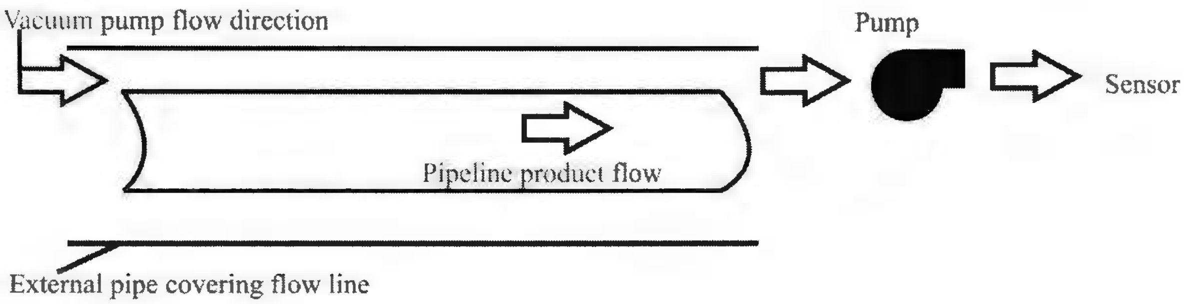
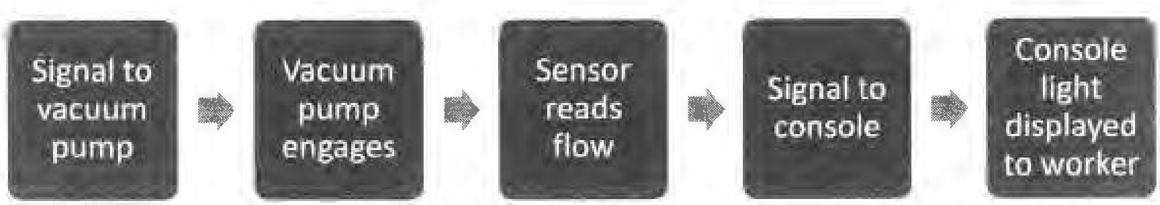


Figure 4.5: Pipe-in-pipe vacuum pump

In a pipe-in-pipe vacuum system, the vacuum is started at regular intervals, and the gas that has been pumped out is analyzed. If hydrocarbons are detected, then the approximate distance to the leak can be determined by the area that is between the two pipes, along with the time that the pumped volume is leaving the area. The hydrocarbon reading can be used to estimate the leak size.

Table 4.8: Pipe-in-pipe vacuum process flow



The fault rate of the system is determined by the PoF of each component, where

$$Probability\ of failure\ (PoF)\ =\ 1 - R(t) \tag{9}$$

Because this system is modeled as a series system, the overall reliability of the system is given by the multiplication of each element, which is lower than component reliability.

Using Equation 8 with the above fault rates, R(t)=0.6385, and the PoF is 1-R(t)=0.36/year. If the consequences are then \$4,500,000, the risk is \$2,250,000. The parameter weight in this case is 0.5.

Risks for other technologies are calculated in the same manner, and are shown in Appendix 1.

4.8.4. Parameter Weighting

A number of calculations were performed on multiple parameters, and specific weights were assigned, as all parameters are not equally significant. For this, industry and expert analysis was used to assign weights. In all cases, parameter weights are calculated subjectively based on industry requirements. Figure 4.2 and Figure 4.3 have multiple branches from higher-level nodes. The branches of risk are calculated from each single node (such as factors affecting operations, technology, and the environment), which splits into subgroups, (in this case, operational reliability, maintenance, decommissioning, etc), which, when summed, total 1. In the case of operational factors, PoF, maintenance, and decommissioning have weight parameters that affect the total risk calculated. For example, PoF risk *1/2 + maintenance risk*1/4 + decommissioning risk*1/4. This is the same for each subcategory in all the hierarchies.

Flow condition parameters do not heavily affect any technology individually, and are all considered to have approximately the same importance, so 1/4 weight for each parameter (as there are four parameters under this node) was considered fair.

For implementation, the most important parameters are construction and range of technology over distance covered. As the equipment and personnel are relatively the same for most technologies, the most important factors are the range that the technology covers, and the resilience during construction.

Some categories are more important that others from a risk point of view, which is why different weights are assigned. The most important regional consideration parameter is for a buried pipe; this is highly desirable as it is the norm when laying subsea pipelines. It will be given a weight of 0.70, while other parameters in this category will be given 0.10.

See Appendix 1 for further details.

4.8.5. **Special Cases**

In certain cases, the parameter being measured can be positive or a negative. In the case of a negative value, exceeding the median will result in a higher risk (due to a higher probability of exceeding a negative median value), and for a positive parameter, exceeding the median will result in a lower risk. Because exceeding the median at any time in the logarithmic equation gives a higher PoF, when test parameters produce positive attributes of exceeding the median, the value must be subtracted from one to correct the probability.

For example, in the tables below, availability greater than the median should reduce the risk. One must know if the criterion is a positive attribute or a detrimental attribute. For positive attributes, 1 is subtracted from $\phi[x]$ to obtain the correct result.

Table 4.9: Commercial Availability (not subtracting one from $\varphi[x]$)

Technological Maturity: Commercial Availability (not subtracting 1 from $\phi[x]$)							
Technology	Ranking	T Median	Φ	$\phi[x]$	Weighted Probability	Cost of Technology	Risk
A	5	6	-0.0912	0.4637	0.0191	$3,000,000	$57,381
B	5	6	-0.0912	0.4637	0.0191	$3,000,000	$57,381
C	3	6	-0.3466	0.3645	0.0150	$3,000,000	$45,101
D	6	6	0.0000	0.5000	0.0206	$4,500,000	$92,813
E	6	6	0.0000	0.5000	0.0206	$2,250,000	$46,406
F	8	6	0.1438	0.5572	0.0183	$3,300,000	$60,278
G	2	6	-0.5493	0.2914	0.0120	$4,370,000	$52,528

Table 4.10: Vendors for Technologies (subtracting 1 from $\varphi[x]$)

Technological Maturity: Commercial Availability							
Technology	Ranking	T Median	Φ	$\phi[x]$	Weighted Probability	Cost of Technology	Risk
A	5	6	-0.0912	0.4637	0.0221	$3,000,000	$66,369
B	5	6	-0.0912	0.4637	0.0221	$3,000,000	$66,369
C	3	6	-0.3466	0.3645	0.0262	$3,000,000	$78,649
D	6	6	0.0000	0.5000	0.0206	$4,500,000	$92,813
E	6	6	0.0000	0.5000	0.0206	$2,250,000	$46,406
F	8	6	0.1438	0.5572	0.0183	$3,300,000	$60,278
G	2	6	-0.5493	0.2914	0.0120	$4,370,000	$52,528

4.9. **Rank of Technologies**

The risk of each technology was computed using the equations and methodology described in the earlier sections, with the risk ranked as follows. All detailed computations are reported in Appendix 1.

Table 4.11: Total risk

Final Total	
Technology	**Risk**
A	**$ 930,615**
B	**$ 855,520**
C	**$ 964,068**
D	**$ 4,476,631**
E	**$ 3,670,692**
F	**$ 1,441,068**
G	**$ 1,613,757**

4.10. **Conclusions**

This chapter has shown how risk analysis can be performed with objective data, using the probability of exceedance of median values for a given criteria. In the case of subsea leak detection analysis, specific criteria were selected and medians were assessed for each technology. The distance of each technology from the mean for each criterion was calculated. This has an advantage over traditional risk-based analysis methods for applications involving multi-criteria decision making, as different problem criteria are analyzed using the same approach, with the conclusion being the same monetary unit.

The practicality in the method is shown in large problems with varied criteria. In these problems, categories can be broken into sub-sections and then each criterion analyzed in comparison to others, while the same methodology is applied to the rest of the criteria. At times, varied scenarios can involve different criteria (spill scenario, MTBF, pipeline flow information) that are difficult to equate without different mathematical methods. The methodology presented solves this problem, by comparing each criterion to others before multiplying the consequences and having the same single monetary unit.

A challenge arises though, in the collection of authentic and applicable objective information on which to base probability of exceedance values. In the present work, the solution to this lack of information is the ranking method described in Section 4.5 using the probability of exceedance.

The conclusion of the risk result is comparable to the BAT approach used by industry in Chapter 3, but here, the use of objective and historical information with a much broader problem scope allows for the consideration of technological, environmental, and maintenance issues.

4.10.1. **Limitations of Evaluation and Future Work**

The values determined for the risk assessment may not be entirely accurate, since they rely on certain assumptions. The following limitations should be noted:

- This study is based on available literature and historical data, and certain assumptions may introduce elements of subjectivity into the analysis.

- Some numbers may not be accurate because of the lack of an actual cost analysis. A problem with quantifying the risk is the subjectivity involved in determining values.
- Certain scenarios would limit the use of particular technologies, so all are not equally suitable for all cases.
- For certain technologies (passive acoustic and/or other point sensors), individual failure along a strand did not affect any calculations for detection. This means that even though there is a failure rate associated with each individual point sensor, it was not considered in the evaluation of risk calculation. Continuous measuring technologies would not present this problem.
- When the strand is broken at any point, continuous measuring technologies will affect the detection along the area after or before the cut. This was not taken into account in the evaluation.
- Because limited information exists about pipe-in-pipe vacuum annulus technology, it was assumed to function in the same way as vacuum tube technology, in terms of detecting leaks. Where appropriate (as with construction/decommissioning costs), different values were used to differentiate the two.
- A simplified diagram and assumptions are used to find the modes of failure for the system.

5. Summary and Conclusions

5.1. Summary

This thesis has explored the concept of risk-based analysis using subjective and objective information in decision-making. The main focus of the study was to show how risk analysis can be performed using objective data as the probability of deviation from normal behavior in a given situation. In the case of subsea leak detection analysis, specific criteria were selected and medians were assessed for each technology using available objective information. Two case studies were analyzed, one on subsea leak detection (SLD) technologies using objective risk, and another using Best Available Technology (BAT) based on subjective risk.

In Chapter 4, the unique method of determining risk was developed and applied to the case study of SLD technologies. The methodology involved the use of historical and objective information to provide a median risk to rate the technologies studied. Each technology was then analyzed for being below or above this median risk threshold. Those below the median risk threshold were the desirable technologies, and those above were undesirable choices for a given criterion. Positive criteria analysis, or BAT, has been used successfully for many applications. In Chapter 3, it was used to determine the best technologies. This allowed for comparing and contrasting the two methods used.

The methodology presented in this thesis is unique; it compares different technologies through the concept of deviation from the median values. It provides a way to look for solutions using attributes and specific criteria applied to all technologies. This methodology simplifies long and complex risk analyses often used in decision-making. It provides a unique and important tool for engineering analysis using a holistic approach. It adds meaning and understanding of risk, and it brings together different information and criteria to a unified value. It provides a helpful mechanism to achieve a single monetary value from historical and objective data for engineering analysis.

Table 5.1: Comparison between methods

Final Total: Risk-based Methodology		
Technology	Rank	Risk
A	2	$ 932,849
B	1	$ 866,522
C	3	$ 953,158
D	7	$ 4,625,614
E	6	$ 3,745,183
F	4	$ 1,567,326
G	5	$ 1,675,673

Final Total: Weighted Average Method	
Technology	Rank
A	2
B	3
C	1
D	6
E	6
F	4
G	5

5.2. Conclusions

Comparing the risk-based method to the BAT weighted average method resulted in the following conclusions:

- The best technologies to monitor a pipeline for arctic subsea application based on the weighted average criteria developed were FOC-based DTS, DSS, DVS/DAS systems and the passive acoustic sensors. The risk-based analysis determined that the best technologies were FOC-distributed sensors, and active and passive acoustic.

- Both methods produce similar results.
- Similar parameters and features in the weighted average method also appear in the risk calculations, e.g., the lowest detectable leak and distance covered for each technology.
- These conclusions confirm the relevance of the risk-based decision-making methodology presented.
- The cost of the pipe-in-pipe and VSS tube method are very high. The calculations reveal that this is because of the time required to check the sensors. As the threshold for detection is higher than other methods, and because of the time required during the vacuum pump operation, the environmental section increases the cost far beyond that of other methods of detection.

Pipe-in-pipe and VSS technologies were removed from risk calculations because of their high cost, and the following conclusions were drawn:

- From the subjective ranking parameters and historical calculations, the first-, second-, and third-placed technologies with the least risk were the vacuum tube, FOC DSS, and FOC DTS.
- The technologies most widely available from vendors were passive acoustic, and then vacuum/vapor sensing tubes.
- The most mature technology was vacuum/vapor sensing tubes; the next was passive acoustic technology.

- Currently, active acoustic point systems technologies are used to monitor pipelines only in high-risk locations, not over the entire pipeline, because of their cost

5.3. **Limitations**

The study has the following limitations:

- This study is based on available literature and historical data, with assumptions outlined in the Scenario section 3.2.
- Because of the lack of actual cost analysis, numbers may not be precise.
- There might be uncertainty in quantifying the risk, as a result of lack of available data for some parameters.
- This study may not apply to all scenarios, as certain scenarios would limit the use of particular technologies.
- The conclusions in the thesis are for specified conditions and cannot be generalized, as individual conditions of the technology, operations, and environment may affect risk.

5.4. **Recommendations**

In addition to the limitations mentioned above, this work could be further improved by the adoption of the following recommendations:

- Numerical evaluation using CFD software to gather information on LDS performance (software such as Ansys FLUENT, CFX, or CFD-Flow may be used for this purpose)
- Large-scale field tests to obtain the operational performance data (this includes the data for minimum leak detection thresholds and minimum time to detect small, chronic leaks)
- Validation of numerical results with field test results
- Assessment of the performance of selected LDS technologies with respect to inspection, maintenance, and retrofit requirements
- Sending industry specific surveys to determine the most important requirements for LDS
- Use of more comprehensive calculations specific to each technology to help improve the accuracy of the risk assessment in the case of failure analysis

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Appendix 1: Calculations

Key	
FOC-Temperature	A
FOC-Strain	B
FOC-Acoustic	C
Pipe-in-Pipe Vacuum	D
Vacuum Tube	E
Passive Acoustic	F
Active Acoustic	G

Subjective Calculation Component							
Technology	A	B	C	D	E	F	G

Flow Conditions	A	B	C	D	E	F	G
Flow Rate	1	1	4	1	1	4	4
Solid Content	1	1	6	1	1	6	2
Pressure Ranges	1	1	7	1	1	6	1
Temperature	3	1	1	1	1	1	1

Implementation	A	B	C	D	E	F	G
Resilience of Technology	6	7	6	8	5	6	6
Equipment and Personnel	5	5	5	9	5	5	9
Range over Pipeline Covered	6	5	5	6	7	4	9

Regional Considerations	A	B	C	D	E	F	G
Depth	1	1	1	1	3	1	1
Temperature	3	1	1	1	1	1	1
Water Clarity	1	1	1	1	1	1	5
Buried Condition	5	1	4	1	5	4	9

Objective Calculation Component

Objective Calculations	A	B	C	D	E	F	G
Commercial Availability	5	5	3	6	6	8	2
Technology Readiness Level	13	13	5	30	30	18	5
MTBF	25	25	25	5	5	25	5
Design Life	20	20	20	10	22	25	25
Decommissioning	2	2	2	7	2	5	3
MTTF	5	5	5	7	2	5	3

Pipeline Conditions: Flow Rate (0.25 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
B	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
C	4	5	-0.11	0.46	0.0094	$3,000,000	$28,189
D	1	5	-0.80	0.21	0.0043	$4,500,000	$19,536
E	1	5	-0.80	0.21	0.0043	$2,250,000	$9,768
F	4	5	-0.11	0.46	0.0094	$3,300,000	$31,008
G	4	5	-0.11	0.46	0.0094	$4,370,000	$41,062

Pipeline Conditions: Solid Content (0.25 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.00	$3,000,000	$13,024
B	1	5	-0.80	0.21	0.00	$3,000,000	$13,024
C	6	5	0.09	0.54	0.01	$3,000,000	$33,185
D	1	5	-0.80	0.21	0.00	$4,500,000	$19,536
E	1	5	-0.80	0.21	0.00	$2,250,000	$9,768
F	6	5	0.09	0.54	0.01	$3,300,000	$36,503
G	2	5	-0.46	0.32	0.01	$4,370,000	$29,151

Pipeline Conditions: Pressure Ranges (0.25 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
B	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
C	7	5	0.17	0.57	0.0117	$3,000,000	$35,071
D	1	5	-0.80	0.21	0.0043	$4,500,000	$19,536
E	1	5	-0.80	0.21	0.0043	$2,250,000	$9,768
F	6	5	0.09	0.54	0.0111	$3,300,000	$36,503
G	1	5	-0.80	0.21	0.0043	$4,370,000	$18,972

Pipeline Conditions: Temperature (0.25 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	3	5	-0.26	0.40	0.0082	$3,000,000	$24,701
B	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
C	1	5	-0.80	0.21	0.0043	$3,000,000	$13,024
D	1	5	-0.80	0.21	0.0043	$4,500,000	$19,536
E	1	5	-0.80	0.24	0.0050	$2,250,000	$11,228
F	1	5	-0.80	0.91	0.0188	$3,300,000	$62,038
G	1	5	-0.80	0.05	0.0011	$4,370,000	$4,939

Implementation: Resilience During Construction (0.50 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	6	5	0.09	0.54	0.0221	$3,000,000	$66,369
B	7	5	0.17	0.57	0.0234	$3,000,000	$70,142
C	6	5	0.09	0.54	0.0221	$3,000,000	$66,369
D	8	5	0.24	0.59	0.0245	$4,500,000	$110,056
E	5	5	0.00	0.50	0.0206	$2,250,000	$46,406
F	6	5	0.09	0.54	0.0221	$3,300,000	$73,006
G	6	5	0.09	0.54	0.0221	$4,370,000	$96,678

Implementation: Equipment and Personnel (0.10 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	5	5	0.00	0.50	0.0041	$3,000,000	$12,375
B	5	5	0.00	0.50	0.0041	$3,000,000	$12,375
C	5	5	0.00	0.50	0.0041	$3,000,000	$12,375
D	9	5	0.29	0.62	0.0051	$4,500,000	$22,853
E	5	5	0.00	0.50	0.0041	$2,250,000	$9,281
F	5	5	0.00	0.50	0.0041	$3,300,000	$13,613
G	9	5	0.29	0.62	0.0051	$4,370,000	$22,193

Implementation: Range Over Pipeline Covered (0.25 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	6	5	0.09	0.54	0.0177	$3,000,000	$53,095
B	5	5	0.00	0.50	0.0165	$3,000,000	$49,500
C	5	5	0.00	0.50	0.0165	$3,000,000	$49,500
D	6	5	0.09	0.54	0.0177	$4,500,000	$79,643
E	7	5	0.17	0.57	0.0187	$2,250,000	$42,085
F	4	5	-0.11	0.46	0.0150	$3,300,000	$49,613
G	9	5	0.29	0.62	0.0203	$4,370,000	$88,773

Regional Considerations: Depth (0.10 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
B	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
C	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
D	1	5	-0.80	0.21	0.0017	$4,500,000	$7,814
E	3	5	-0.26	0.40	0.0033	$2,250,000	$7,410
F	1	5	-0.80	0.21	0.0017	$3,300,000	$5,731
G	1	5	-0.80	0.21	0.0017	$4,370,000	$7,589

Regional Considerations: Water Temperature (0.10 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	3	5	-0.26	0.40	0.0033	$3,000,000	$9,880
B	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
C	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
D	1	5	-0.80	0.21	0.0017	$4,500,000	$7,814
E	1	5	-0.80	0.21	0.0017	$2,250,000	$3,907
F	1	5	-0.80	0.21	0.0017	$3,300,000	$5,731
G	1	5	-0.80	0.21	0.0017	$4,370,000	$7,589

Regional Considerations: Water Clarity (0.10 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
B	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
C	1	5	-0.80	0.21	0.0017	$3,000,000	$5,210
D	1	5	-0.80	0.21	0.0017	$4,500,000	$7,814
E	1	5	-0.80	0.21	0.0017	$2,250,000	$3,907
F	1	5	-0.80	0.21	0.0017	$3,300,000	$5,731
G	1	5	-0.80	0.21	0.0017	$4,370,000	$7,589

Regional Considerations: Buried Condition (0.70 Weightage)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	5	5	0.00	0.50	0.0289	$3,000,000	$86,625
B	1	5	-0.80	0.21	0.0122	$3,000,000	$36,468
C	4	5	-0.11	0.46	0.0263	$3,000,000	$78,929
D	1	5	-0.80	0.21	0.0122	$4,500,000	$54,701
E	5	5	0.00	0.50	0.0289	$2,250,000	$64,969
F	4	5	-0.11	0.46	0.0263	$3,300,000	$86,822
G	9	5	0.29	0.62	0.0355	$4,370,000	$155,352

Maintenance: MTBF (0.50 weight)							
Technology	Ranking	T Median	Φ	φ[x]	Weighted Probability	Cost of Technology	Risk
A	13	18	-0.1486	0.4409	0.0182	$3,000,000	$54,564
B	13	18	-0.1486	0.4409	0.0182	$3,000,000	$54,564
C	5	18	-0.6264	0.2655	0.0110	$3,000,000	$32,860
D	30	18	0.2695	0.6062	0.0250	$4,500,000	$112,531
E	30	18	0.2695	0.6062	0.0250	$2,250,000	$56,265
F	18	18	0.0141	0.5056	0.0209	$3,300,000	$68,827
G	5	18	-0.6264	0.2655	0.0110	$4,370,000	$47,866

Technological Maturity: Commercial Availability							
Technology	Ranking	T Median	Φ	φ[x]	Weighted Probability	Cost of Technology	Risk
A	5	6	-0.0912	0.4637	0.0221	$3,000,000	$66,369
B	5	6	-0.0912	0.4637	0.0221	$3,000,000	$66,369
C	3	6	-0.3466	0.3645	0.0262	$3,000,000	$78,649
D	6	6	0.0000	0.5000	0.0206	$4,500,000	$92,813
E	6	6	0.0000	0.5000	0.0206	$2,250,000	$46,406
F	8	6	0.1438	0.5572	0.0183	$3,300,000	$60,278
G	2	6	-0.5493	0.2914	0.0292	$4,370,000	$127,734

Technological Maturity: Level of Maturity							
Technology	Ranking	T Median	Φ	φ[x]	Weighted Probability	Cost of Technology	Risk
A	14	20	-0.1657	0.4342	0.0233	$3,000,000	$70,017
B	20	20	0.0127	0.5051	0.0204	$3,000,000	$61,250
C	8	20	-0.4455	0.3280	0.0277	$3,000,000	$83,162
D	31	20	0.2318	0.5916	0.0168	$4,500,000	$75,800
E	31	20	0.2318	0.5916	0.0168	$2,250,000	$37,900
F	19	20	-0.0130	0.4948	0.0208	$3,300,000	$68,768
G	8	20	-0.4455	0.3280	0.0277	$4,370,000	$121,139

Decommissioning (0.25 weight)							
Technology	Ranking	T Median	Φ	ϕ[x]	Weighted Probability	Cost of Technology	Risk
A	2	5	-0.4055	0.3426	0.0283	$3,000,000	$84,786
B	2	5	-0.4055	0.3426	0.0283	$3,000,000	$84,786
C	2	5	-0.4055	0.3426	0.0283	$3,000,000	$84,786
D	7	5	0.2209	0.5874	0.0485	$4,500,000	$218,080
E	2	5	-0.4055	0.3426	0.0283	$2,250,000	$63,589
F	5	5	0.0527	0.5210	0.0430	$3,300,000	$141,844
G	3	5	-0.2027	0.4197	0.0346	$4,370,000	$151,302

Environment: Clean up due to Spill (0.50 weight)					
Technologies	Pipeline bbl/sec	Time in Seconds to Detect	Amount bbls	Cost per Barrel	Total Damage Cost
FOC	0.58	300	174	$4,200	$120,313
FOC	0.58	300	174	$4,200	$120,313
FOC	0.58	300	174	$4,200	$120,313
PIP/Vacuum	0.58	7200	4167	$4,200	$2,887,500
PIP/Vacuum	0.58	7200	4167	$4,200	$2,887,500
Passive Acoustic	0.58	300	174	$4,200	$120,313
Active Acoustic	0.58	300	174	$4,200	$120,313

Environment: Detectable Percent of Flow (0.50 weight)					
Technologies	Detect able % of flow	ϕ[x] Probability of not being detected	POD=1-ϕ[x]	Cost of Technology	Risk
FOC	0.001	0.440	0.560	$3,000,000	$217,737
Pipe in pipe	0.018	0.911	0.089	$4,500,000	$676,374
Vacuum Tube	0.018	0.911	0.089	$2,250,000	$338,187
Passive Acoustic	0.091	0.984	0.016	$3,300,000	$535,937
Active Acoustic	0.004	0.713	0.287	$4,370,000	$514,132

Final Total: Risk-based Methodology		
Technology	**Rank**	**Risk**
A	2	$ 930,615
B	1	$ 855,520
C	3	$ 964,068
D	7	$ 4,476,631
E	6	$ 3,670,692
F	4	$ 1,441,068
G	5	$ 1,613,757